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 #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).

5.3 Hydroelectric Incentive Mechanism Variance Account

The Hydroelectric Incentive Mechanism Variance Account was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. This account records a credit to ratepayers of 50 per cent of hydroelectric incentive mechanism ("HIM") revenues above an OEB-specified threshold.[9]

The threshold specified in EB-2013-0321 (payment amount order, Appendix G, page 7) and in EB-2014-0370 (payment amount order, Appendix B, pages 8-9) was $51.0M for 2014 and $58.0M for 2015. After December 31, 2015, the annual threshold was set at $54.5M in EB-2014-0370 (payment amounts order, Appendix B, page 9) based on the average 2014-2015 threshold. OPG proposes that the threshold of $54.5M continue as of the effective date of the payment amounts order in this proceeding.

There were no additions to the account for 2015 as actual HIM revenues during 2015 were $26.5M. These revenues were significantly below the specified threshold of $58M, as shown in Ex. H1-1-1 Table 4.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account was originally approved in EB-2010-0008 and has been approved in all subsequent OPG applications. This account records the financial impact of foregone production at the regulated hydroelectric facilities due to surplus baseload generation ("SBG") conditions.

For the same reasons as noted in the description of the Hydroelectric Water Conditions Variance Account above, the 27 small regulated hydroelectric facilities not listed in Attachment 3, which comprised less than two per cent of total regulated hydroelectric production, are excluded from the scope of this account.

[9] The methodology used to record entries into this account is the same as previously approved by the OEB.

Entries in the account have been and are proposed to continue to be calculated by multiplying the foregone production volume due to SBG conditions (in MWh) by the approved regulated hydroelectric payment amount in effect, net of the avoided GRC costs.[10]

As described in EB-2013-0321, Ex. E1-2-1, section 3.2, OPG calculates foregone production due to SBG by starting with the total volume of spill and subtracting the volume of spill due to:

- water conveyance constraints (e.g., Sir Adam Beck Generating Station tunnel capacity constraints);
- production capability constraints (e.g., unit outages; operating regulatory requirements etc.);
- market constraints (i.e., IESO dispatch constraints: market or transmission system); and
- contractual obligations (e.g., regulation service).

The remaining spill volume is identified as potential SBG spill. From this potential spill volume, OPG excludes spill that occurs when the Ontario market price is above the level of the GRC. The volume of spill remaining after this adjustment is the foregone production due to SBG that is used to record entries in this account.[11]

This account records and is proposed to continue to record any variances, as a result of foregone production due to SBG conditions, in the amounts payable to the St. Lawrence Seaway Management Corporation for the conveyance of water in the Welland Ship Canal and any related variances in the amounts payable to Government of Quebec for water rentals.

---

[10] Prior to the effective date of the payment amounts order in this proceeding, the revenue impact of SBG conditions is determined by multiplying the forgone production volume by the OEB-approved previously regulated hydroelectric payment amount of $40.20/MWh or the OEB-approved newly regulated hydroelectric payment amount of $41.93/MWh, as applicable. As of the effective date of the payment amounts order in this proceeding, OPG proposes to determine the revenue impact by using the OEB-approved payment amounts in effect for all regulated hydroelectric facilities pursuant to the OEB-approved incentive regulation formula.
[11] The methodology used to record entries into this account is the same as previously approved by the OEB.

The derivation of the debit addition to this account of $81.5M for 2015, reflecting approximately 2.8 TWh of total SBG spill, is shown in Ex. H1-1-1 Table 5.

5.5 Income and Other Taxes Variance Account

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account records, and is proposed to continue to record, the financial impact on the revenue requirement of the following[12]:

- Any differences in payments in lieu of corporate income or capital taxes that result from a legislative or regulatory change to the tax rates or rules of the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (formerly the *Corporations Tax Act* (Ontario), as modified by the regulations under the *Electricity Act, 1998*, and any differences in payments in lieu of property tax to the Ontario Electricity Financial Corporation that result from changes to the regulations under the *Electricity Act, 1998*;
- Any differences in municipal property taxes that result from a legislative or regulatory change to the tax rates or rules for OPG's prescribed assets under the *Assessment Act, 1990*;
- Any differences in payments in lieu of corporate income or capital taxes that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, or court decisions on other taxpayers; and,
- Any differences in payments in lieu of income or capital taxes that result from assessments or re-assessments (including re-assessments associated with the application of the tax rates and rules to OPG's regulated operations or changes in assessing or administrative policy including those arising from court decisions on other taxpayers). OPG continues to be subject to tax audits from prior years dating back to 2013.

[12] The methodology used to record entries into this account is the same as previously approved by the OEB.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported by the IESO was 137.0 TWh in each of 2016 and 2015, which excludes electricity exports out of the province.

Baseload generation supply surplus in Ontario was more prevalent in 2016 than in 2015, mainly due to higher water flows in the province during 2016 and limitations on the export of surplus power out of the province, primarily due to transmission constraints in the state of New York. Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and other grid-connected renewable resources. Reducing hydroelectric production, which often results in spilling of water, is the first measure used by the IESO to manage SBG conditions. During 2016 and 2015, OPG lost 4.7 TWh and 3.2 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2016 and 2015 was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2016 was 6.9 cents per kilowatt hour (¢/kWh), compared to 6.5 ¢/kWh during 2015. The average sales price in 2016 reflected the higher OEB-authorized nuclear rate rider of $10.84/MWh for recovery of variance and deferral account balances in effect during the full year. The average sales price for the Regulated – Hydroelectric segment was 4.4 ¢/kWh, compared to 4.7 ¢/kWh during 2015. The decrease was primarily due to a lower rate rider in effect during 2016 related to the recovery of variance and deferral account balances for the hydroelectric facilities prescribed for rate regulation prior to 2014. These rate riders were established to recover approved balances recorded in OEB-authorized regulatory variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to regulatory account balances.

Cash Flow from Operations

Cash flow provided by operating activities for 2016 was $1,705 million, compared to $1,465 million for 2015. The increase in cash flow provided by operating activities for 2016, compared to 2015, was primarily due to higher generation revenue receipts reflecting higher nuclear rate riders and higher nuclear generation in 2016. The increase in cash flow was also due to lower pension plan contributions in 2016 reflecting an updated actuarial valuation of the OPG registered pension plan. The increase in cash flow was partially offset by higher OM&A expenditures during 2016, compared to 2015, and the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to the period from January 1, 2015 to December 4, 2015. The rebate was made pursuant to a provision under the lease agreement for the Bruce nuclear generating stations. This provision was eliminated effective December 4, 2015 as part of the 2015 amendments to the lease agreement.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. During each of the years of 2016 and 2015, the FFO Adjusted Interest Coverage was 5.1 times. The FFO Adjusted Interest Coverage in 2016 reflected a year-over-year increase in cash flow provided by operating activities, offset by lower working capital balances.

will record 1/12th of the annual deferral amount each month. OPG's rate smoothing proposal is described at Ex. A1-3-3 and the proposed annual deferral amounts are shown in Ex. A1-3-3, Chart 4.

The regulation 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. The regulation also stipulates that the deferral account shall record interest on the balance of the account at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB from time to time, compounded annually. OPG will record interest based on the monthly opening balance in the account.

6.2 Mid-term Nuclear Production Variance Account

As set out in detail in Ex. A1-3-3, OPG seeks approval to file an application in the first half of 2019 to review and update the nuclear production forecast and corresponding fuel costs for the July 1, 2019 to December 31, 2021 period. To effect this proposal, OPG proposes establishing the Mid-term Nuclear Production Variance Account to record the impact of the production variance from July 1, 2019 to December 2021. The production variance will be the difference between: (i) the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast approved in the mid-term review application. 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.

OPG's 2017-2021 nuclear production forecast is presented in Ex. E2-1-1. OPG's rate smoothing and mid-term production review proposals are described at Ex. A1-3-3. As described in Ex. A1-3-3, the purpose of this account is to mitigate the significant production risk associated with setting nuclear payment amounts over the five-year term of this Application. That production risk is expected to increase during the second half of the five-year term in light of the DRP and work to enable Pickering Extended Operations.

This account would protect both customers and OPG symmetrically, depending on whether OPG's nuclear production forecast approved at the mid-term production review application is higher or lower than the nuclear production forecast approved in this Application. If production is higher than currently forecast, the higher production would result in a credit balance in the account, to be refunded to customers. If production is lower than forecast, OPG may not recover its revenue requirement and a debit balance in the account would be required. Mitigating this risk benefits both customers and the company.

Since the inception of regulation by the OEB, there have been a number of variances between OEB–approved production forecasts and actual production. It has proven difficult to forecast nuclear production in the past where OPG's Pickering and Darlington facilities were operating in a comparatively steady state when compared to the operating circumstances that will be facing these facilities during the upcoming application period. Even with the mid-term production review, the proposed ratemaking methodology will result in a substantial increase in production forecast risk compared to previous applications.[28]

This account is proposed to take effect on July 1, 2019.

6.3 Nuclear ROE Variance Account

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.

OPG's Application incorporates an ROE of 9.19 per cent for each year of the test period for the nuclear business, as this is the latest rate published by the OEB. The OEB's cost of capital parameters, including prescribed ROE, are updated on an annual basis. For the

[28] In previous applications, OPG's payment amounts have been based on forecast production of two years or less.

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.

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F3
Tab 1
Schedule 1
Table 1

Table 1
Corporate Support & Administrative Groups - OPG ($M)

Line No.	Corporate Costs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Business and Administrative Service[1]	295.6	281.7	285.5	292.5	292.4	284.4	286.6	287.1	289.6
2	Finance	63.9	59.0	51.4	57.5	58.1	56.0	55.7	54.9	55.8
3	People and Culture	115.1	118.1	115.9	111.2	115.0	113.7	116.3	117.3	119.3
4	Commercial Operations and Environment	37.4	43.0	37.2	44.0	42.8	40.9	41.9	41.3	44.8
5	Corporate Centre	50.8	47.4	61.9	68.2	65.4	65.5	65.7	66.9	67.8
6	Total	562.8	549.2	551.9	573.4	573.7	560.5	566.2	567.5	577.3

Notes:
1 Business and Administrative Service costs exclude amounts captured in the Asset Service Fee.

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F3
Tab 1
Schedule 1
Table 3

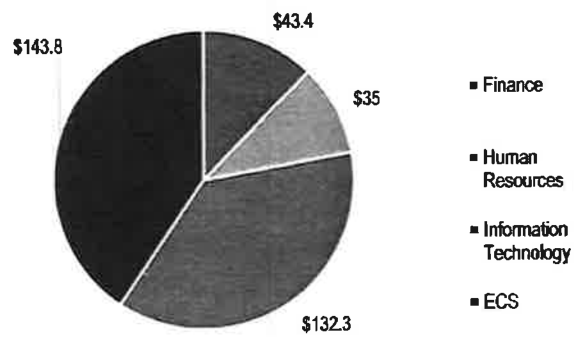
Table 3
Allocation of Corporate Support & Administrative Costs - Nuclear ($M)

Line No.	Corporate Group	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Business and Administrative Service	246.6	227.2	231.0	245.0	246.1	239.1	241.0	242.3	246.1
2	Finance	46.3	44.4	35.6	40.2	41.5	39.4	39.0	38.8	39.9
3	People and Culture	91.6	98.2	95.8	92.4	96.2	95.3	97.8	98.5	100.5
4	Commercial Operations and Environment	14.7	19.5	16.8	20.4	20.2	18.9	19.9	19.6	21.8
5	Corporate Centre	29.2	26.9	39.6	44.3	44.9	44.5	45.0	45.8	45.8
6	Total	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1

Overall costs declined 10% from 2010 to 2014 while headcount declined 11%. OPG's costs declined 12% in IT, 10% in HR, 16% in Finance and 7% in ECS

2010 Costs

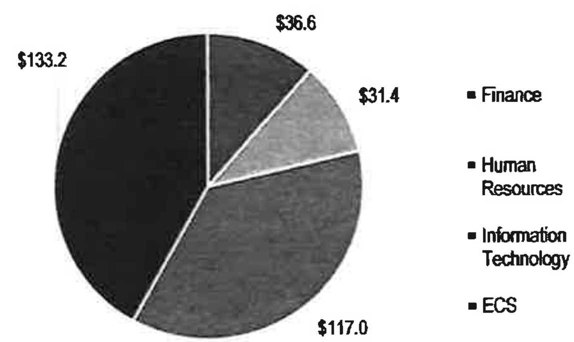
2010 Total Corporate Function Cost = $354.5 Million



2010 OPG Employees = 10,305

2014 Costs

2014 Total Corporate Function Cost = $318.2 Million



2014 OPG Employees = 9,292

*2010 costs have been adjusted for inflation

The Hackett Group

complete.[30] The proposed nuclear Custom IR framework attempts to strike such a balance, reflecting the fact that OPG's capital and operating costs will vary significantly with the refurbishment of the Darlington facility and the extension of operations at Pickering, but also implementing benchmark-driven stretch reductions in aspects of the company's nuclear operations where it is reasonable to do so.

The proposed nuclear Custom IR framework reflects the OEB's conclusions. It is based on five individual nuclear revenue requirements, but includes incremental stretch reductions that are sustained, year-over-year, creating a meaningful incentive to continuously improve performance and cost efficiency during the IR period.

3.2. Stretch Factor Proposal

As described above, any form of incentive regulation proposed for OPG's nuclear assets must be appropriate in the context of the significant programs planned for the company's nuclear facilities during the IR period. OPG proposes a benchmark-based stretch factor that will provide a meaningful performance incentive during the term of this application.

OPG recognizes the OEB's expectation that an IR mechanism should incent performance improvements, and should be based on measures that are external to the company's forecasts. To achieve this, **OPG proposes to apply a benchmark-based stretch factor to revenue requirement attributable to the company's nuclear Base OM&A and allocated corporate support services OM&A.**[31] This reduction is in addition to the performance improvement initiatives reflected in the company's gap-based nuclear business planning process. The proposed stretch reduction has the effect of reducing revenue requirement for these two significant categories of expenditures below forecast.

---

[30] OEB Consultation Report, p. 9.
[31] Descriptions of nuclear Base OM&A and corporate support services are available at Ex. F2-2-1 and Ex. F3-1-1, respectively.

years, on the presumption that the company should be incented to find additional savings each year). Reductions are proposed beginning in 2018, with additional reductions in 2019, 2020, and 2021. This mirrors the operation of the stretch factor under 4GIRM.

Chart 10 shows the product of applying the 0.3% stretch factor to Base OM&A and allocated corporate support OM&A.

Chart 10 – Stretch Reduction Amounts

($M)	2018	2019	2020	2021
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	**5.0**	**10.1**	**15.2**	**20.4**
Base & Corporate Support OM&A Used to Determine Payment Amounts	**1,658.2**	**1,681.0**	**1,694.5**	**1,710.0**

The total reduction over the term of the application is $50.6M. Although the 0.3% stretch reduction is constant, the "snow plow" effect of maintaining prior years' reductions means that the $20.4M reduction in 2021 is a 1.2% reduction to that year's stretch-eligible OM&A, or a 0.9% reduction to total nuclear OM&A.

This stretch reduction is incremental to the performance improvements required to achieve OPG's business plan. Customers will benefit from these "up-front" budget reductions, and OPG will bear the risk of any shortfall.

3.2.2. Productivity Factor is Not Applicable

OPG is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor. The nature and scale of capital work planned for the IR period mean that past productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period.

EP Interrogatory #26

Issue Number: 6.7
Issue: Are the corporate costs allocated to the nuclear businesses appropriate?

Interrogatory

Reference:
Application, Ex F3-T1-Sch 1-Table 1, Table 3

The corporate costs shown in these tables are either directly assigned or allocated to the regulated businesses. The latter amounts are based on drivers. (Ex F3-T1-Sch 1 at page 1).

1. The corporate support and administrative costs in Table 1 ($562.8 in 2013) appear to be the total of all allocated costs of OPG's various businesses. Since the title of Table 1 refers to "groups', please indicate which OPG businesses or entities other than its nuclear business have the costs shown in Table 1 allocated to them.

2. For each amount shown in Table 3, please state the dollar portion thereof that is directly assigned and the portion thereof that is allocated based on drivers.

3. Please confirm or disconfirm the following:

   a. that the share of OPG's Corporate Support & Administrative Costs that are allocated to the nuclear business is 76.1% in 2013 and 78.7% in 2021 (Plan)

   b. that for the years 2013-2015, that average annual share of those costs was $421 million and for the years 2016-2021, the average annual share is $445 million

   c. that shares of OPG Corporate Support & Administrative Costs allocated to the nuclear business are:

	2013 Actual	2021 Plan
Business & Admin	83.42%	84.98%
Finance	72.46%	71.51%
People & Culture	79.58%	84.24%
Commercial Ops	39.30%	48.66%
Corporate Centre	57.48%	67.55%

Witness Panel: Corporate Groups, Compensation

Response

1. The amounts listed in Ex. F3-1-1, p. 1, lines 10-12 represent total OPG Corporate Support and Administrative costs. The term "groups" in Ex. F3-1-1, Table 1 refers to business areas included in Corporate Costs (i.e. Business and Administrative Service, Finance, People and Culture, Commercial Operations & Environment, and Corporate Centre). Other than its nuclear business, Corporate Costs are either directly assigned or allocated to OPG's regulated hydroelectric and unregulated businesses.

2. Please refer to Attachment 1 for support services costs directly assigned and allocated to the nuclear business for the amounts shown in Ex. F3-1-1, Table 3.

3. OPG confirms parts (a) to (c).