K20.3

EB 2016-0152

CONSUMERS COUNCIL OF CANADA

COMPENDIUM-WITNESS PANEL 5B

EXHIBIT ______

Table 1 provides the revenue requirement impacts of the OEB-approved forecast in-service additions in the approved hydroelectric payment amounts. The revenue requirement impacts of the in-service additions for each of total regulated hydroelectric capital, CRVA eligible projects and Sustaining Capital projects are shown on lines 8, 16, and 24. The values in the "Annual Average" column represent the annualized amounts embedded in the current payment amounts.

Table 2 provides the gross cost of total OEB-approved regulated hydroelectric in service additions (line 3), the accumulated depreciations for these additions (line 6), and the associated average net plant rate base amount (line 9). These amounts are then broken out by CRVA eligible projects and Sustaining Capital projects, with the in-service additions shown for each of these categories on lines 12 and 21.

3.0 MECHANICS OF DETERMINING AND RECORDING AMOUNTS TO THE CRVA

OPG does not propose to alter the types of variances that are recorded to the CRVA during the 2017 to 2021 period in respect of the prescribed hydroelectric facilities, relative to the types of variances it has measured in prior periods. In accordance with O. Reg. 53/05, OPG expects the CRVA would continue to record the revenue requirement variance between (a) the *forecast* capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed hydroelectric generating facility underpinning the OEB-approved revenue requirement for CRVA-eligible projects in EB-2013-0321, and (b) such *actual*, prudent capital and non-capital costs and firm financial commitments.

The determination of the variance between items (a) and (b) above can be thought of as the following two separate transactions[4]:

1) **Credit Entries for OEB-Approved Amounts**: These amounts reflect in-service additions that are funded in the "going in" hydroelectric payment amounts for CRVA-eligible projects. In setting base payment amounts, the OEB approved incremental

[4] Interest recorded and amortization of balances approved for disposition are not considered for the purpose of this evidence as they distinct from the amounts recorded in the account. No changes to the mechanics for interest and amortization entries in the account are anticipated. Amortization amounts will continue to be based on amounts ultimately approved by the OEB for disposition.

depreciation expense, interest cost, return on equity ("ROE"), and income tax expense related to these in-service additions. The CRVA will reflect the fact that those approvals in the revenue requirement will continue to underlie the approved payment amounts, and will credit them back to customers.

2) Debit Entries for OPG Actual Incurred Costs: These amounts will reflect the revenue requirement impact of the costs that OPG actually incurs in relation to CRVA-eligible projects placed in service during the IR period that were not reflected in the "going in" payment amounts. When such a CRVA-eligible project enters service, the actual cost, depreciation rate, and timing of that project in conjunction with the OEB-approved annual interest and ROE rates reflected in the "going in" payment amounts and associated income taxes will be used to determine the revenue requirement impact recorded in the account for future recovery from ratepayers.

The balance of the CRVA account will be the net of the credit for amounts already included in payment amounts (i.e., Entry 1) and the revenue requirement impact of the actual in-service additions for CRVA-eligible projects described above (i.e., Entry 2).

During the hearing of this application, OPG identified an amount of approximately $2M as the total hydroelectric CRVA related revenue requirement for 2014 and 2015 in-service additions.[5] This amount can be found in Table 1 line 16 (columns (a) and (b)). This amount represents the combined revenue requirement impact of 2014 and 2015 forecast in-service additions reflected in the current hydroelectric payment amounts. The annual average of these amounts is approximately $0.9M as identified in line 16, column (c) of Table 1. This annual average is the amount that OPG proposes be used to determine the customer credit entry into the CRVA for CRVA amounts already funded in payment amounts. The revenue requirement impact will continue to reflect an annual $0.9M credit to customers in the CRVA until rebasing.

OPG will continue to record in the CRVA the actual revenue requirement of costs incurred for eligible projects not reflected in the "going in" payment amounts that enter service during the 2017 to 2021 period, as described under Entry 2 above. Since the OEB has not approved any

[5] EB-2016-0152, Transcript, Day 10, page 145, lines 17-20.

CRVA-eligible projects for this period, the base payment amounts include no associated costs, and the full revenue requirement impact of these in service amounts would be recorded in the account. As discussed in section 4.0 below, the ultimate recovery of these amounts would be subject to a test that ensures no 'double recovery' of these amounts through capital-related revenues during the IR period.

4.0 PREVENTING DOUBLE RECOVERY

In principle, OPG understands that rate-setting through a price-cap index decouples payments and costs. As a result, it is not strictly accurate to state that approved payment amounts fund a specific level of capital expenditures during the IRM period. Under this form of incentive rate-setting, a regulated entity retains the discretion to manage its business within the envelope of funding provided, responding to its individual cost pressures and opportunities to make efficiency gains.

However, while O. Reg. 53/05 requires that OPG recover prudently incurred costs associated with CRVA-eligible projects, it does not permit OPG to recover those costs once in base payment amounts and again through disposition of deferral and variance accounts. In that context, OPG acknowledges that it would only be appropriate for it to recover any balance in the CRVA if it can demonstrate that the costs of the projects recorded in the account have not been funded through base payment amounts during the 2017-2021 period.

Therefore, in OPG's submission, it would only be necessary for the OEB to allow recovery of CRVA balances if OPG's total prudent capital spending in the 2017 to 2021 period (i.e., CRVA-eligible and Sustaining Capital projects combined) exceeds the total amount of such capital spending implicitly funded through base payment amounts.

As a practical matter the depreciation expense in base payment amounts represents the source of cash flow that will be available to fund capital expenditures during the 2017 to 2021 period, escalated by the annual price-cap index adjustments approved by the OEB during the term. OPG has calculated the annual total of these amounts, escalated by the proposed 1.5% price-cap index in Table 3 of this schedule. At the production level reflected in approved "going in" payment amounts, these components of the IRM payment amounts would provide approximately $749M in revenues that could be invested in capital over the IR period.

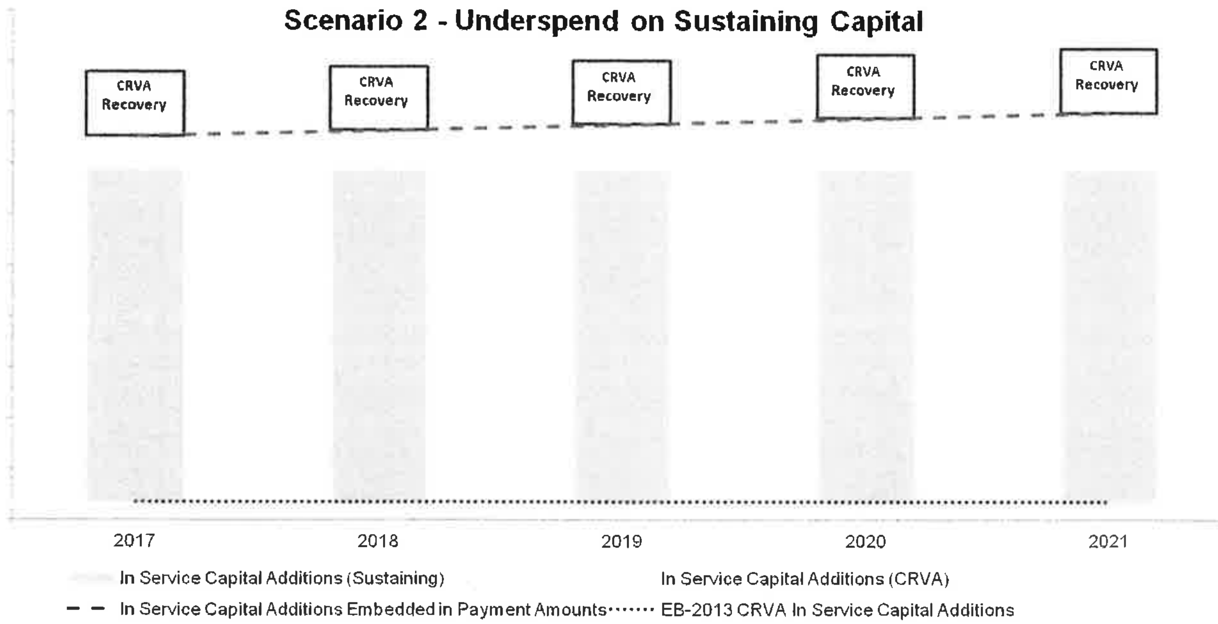


Chart 2

Hydro CRVA Clearance Methodology (Scenario 2: Underspend on Sustaining Capital)

Line No.	Description	2017	2018	2019	2020	2021	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Illustrative Actual CRVA-Related In-Service Additions	25.0	25.0	25.0	25.0	25.0	125.0
2	Revenue Requirement Impact of CRVA Related In-Service Additions[1]	1.3	3.8	6.3	8.8	11.3	31.3
3	CRVA amounts in Payment Amount (Credit to CRVA)[2] *(Per EB-2013-0321)*	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(4.7)
4	Balance in CRVA Account *(line 2 + line 3)*	0.3	2.8	5.3	7.8	10.3	26.5
CRVA Recoverability Threshold							
5	Total In-Service Additions Funded Through Payment Amounts[3]	145.4	147.6	149.8	152.0	154.3	749.1
6	Illustrative Actual Sustaining-Related In-Service Additions	130.0	130.0	130.0	130.0	130.0	650.0
7	Illustrative Actual CRVA-Related In-Service Additions	25.0	25.0	25.0	25.0	25.0	125.0
8	Total Illustrative In-Service Additions	155.0	155.0	155.0	155.0	155.0	775.0
9	In Service Additions Not Funded Through Rates *(line 8 - line 5)*	9.6	7.4	5.2	3.0	0.7	25.9
10	Revenue Requirement Impact of In Service Additions Not Funded Through Payment Amount[1]	0.5	1.3	2.0	2.4	2.6	8.7
11	Maximum Recoverable CRVA Balance (Lesser of Line 4 and Line 10)[4]						8.7

Notes:
1 Approximate Revenue Requirement Impact of 10%, and assuming 1/2 year rule
2 Revenue Requirement Impact of EB-2013-0321 Average of 2014 and 2015 CRVA In Service Additions (See H1-1-2 Table 1 line 16)
3 H1-1-2 Table 3 Line 1
4 Limited to a credit $4.7M - representing the CRVA related in-service additions funded through rates at line 3

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F2
Tab 7
Schedule 1
Table 1

Table 1
OM&A - Darlington Refurbishment ($M)

Line No.	Description	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	Darlington Refurbishment - Unit Refurbishment[1]	4.6	4.3	1.4	1.0	41.5	13.8	3.5	48.4	19.7
2	Facilities and Infrastructure Projects[2]	1.7	2.0	0.1	0.3	0.0	0.0	0.0	0.0	0.0
3	Safety Improvement Opportunities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Total Darlington Refurbishment OM&A	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7

Notes:
1 The Unit Refurbishment 2016-2021 amounts include removal costs of existing structures or facilities, and L&ILW variable expense.
2 The F&IP 2013-2021 numbers include removal costs of existing structures or facilities prior to construction or modification.

generators, feeders, 'balance of plant' components (including fueling machine maintenance). Examples of the work expected to be performed include spacer location and relocation work, additional steam generator water-lancing and feeder replacements.

The costs to enable Extended Operations are forecast to be $307M from 2016 to 2020. These costs include those to complete the Periodic Safety Review, the Fuel Channel Life Assurance project, component condition assessments, incremental outage inspections and maintenance programs and potential modifications that are required to demonstrate fitness-for-service beyond 2020 and maintain safe, reliable operations. Chart 2 below shows the breakdown of these costs.

Chart 2: Pickering Extended Operations – Enabling Costs ($M)

Line No.	Cost Item	2016	2017	2018	2019	2020	Total	Reference
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Base OM&A**	11.0	1.0	0.0	0.0	0.0	12.0	Ex. F2-2-1 Table 1
2	**Outage OM&A:**							
3	**Pickering Station**	0.0	12.2	11.6	20.8	22.8		Ex. F2-4-1 Table 1
4	**Nuclear Support**	0.0	9.9	25.7	67.9	62.8		Ex. F2-4-1 Table 1
5	**Total Outage OM&A**	0.0	22.1	37.3	88.7	85.6	233.7	
6	**Project OM&A**	4.0	2.5	18.0	18.4	18.7	61.6	Ex. F2-3-1 Table 1
7	**Total Pickering Extended Operations**	15.0	25.6	55.3	107.1	104.3	307.2	

3.3.2 Normal Operations and their Associated Cost

With shutdown previously anticipated in 2020, ongoing operations and their costs were set to decline starting in 2017. With Extended Operations, OPG needs to restore on-going operating and maintenance programs to normal levels for the 2017 to 2020 period. For example, outages requirements set to decline under the previous plan will now need to be reinstated. As well, both OM&A and capital projects need to be restored to the levels required to continue to operate safely for four additional years and to maintain or improve plant reliability during that time. The costs in this category shown in Chart 1 are those

Numbers may not add due to rounding

Filed: 2017-03-08
EB-2016-0152
Exhibit N3
Tab 1
Schedule 1
Attachment 2
Table 17

Table 17
Updated L-11.6-20 VECC-051 Chart 4
OPG Proposed Deferred Nuclear Revenue Requirement

	2017	2018	2019	2020	2021
Proposed Revenue Requirement* ($M)	$ 3,161	$ 3,186	$ 3,273	$ 3,783	$ 3,398
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Unsmoothed Rate ($/MWh)	$ 82.98	$ 82.81	$ 83.87	$ 101.28	$ 96.03
Smoothed Rate ($/MWh)	$ 76.39	$ 78.60	$ 84.83	$ 88.21	$ 92.02
Smoothed Revenue ($M)	$ 2,910	$ 3,024	$ 3,311	$ 3,295	$ 3,256
Deferred Revenue Requirement ($M)	$ 251	$ 162	$ (38)	$ 488	$ 142

* Revenue requirement for 2017-2021 based on I tables in N2 update as of Feb 2017

UNDERTAKING J8.3

Undertaking

What is the revenue requirement for 2020 and 2021 specific to Unit 2 contingency costs.

Response

The revenue requirement specific to expending and placing in service the Darlington Unit 2 contingency of $694.1M is approximately $56M in 2020 and $67M in 2021. Additionally, there are credits to ratepayers of approximately $2M in 2018 and $12M in 2019 reflected in the proposed revenue requirement on account of contingency expenditures, related to capital cost allowance tax deductions.[1]

These estimated amounts were derived in the manner shown in L-4.3-2 AMPCO-077.

---

[1] The incremental revenue requirement impact of these credits is partly reflected in the 2017 proposed revenue requirement through the effect of carrying back projected 2018 and 2019 regulatory tax losses to 2017, as noted in Ex. N2-1-1, p. 3, lines 11-17.

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

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit G2
Tab 2
Schedule 1
Table 1

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	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)
	Non-Derivative Portion:									
1	**Bruce Lease Revenues**	261.2	262.8	266.1	237.4	251.1	246.5	245.0	257.4	223.6
2	**Bruce Costs**	230.5	191.1	259.0	303.4	317.3	320.9	330.8	339.5	316.8
3	**Bruce Lease Net Revenues**	30.7	71.7	7.1	(66.0)	(66.1)	(74.3)	(85.9)	(82.1)	(93.1)
	Derivative Portion:									
4	**Bruce Lease Revenues**	(32.8)	44.7	224.9	0.0	0.0	0.0	0.0	0.0	0.0
5	**Bruce Costs (Income Tax)**	(8.2)	11.2	56.2	0.0	0.0	0.0	0.0	0.0	0.0
6	**Total Derivative Impact**	(24.6)	33.5	168.7	0.0	0.0	0.0	0.0	0.0	0.0
	Total:									
7	**Bruce Lease Revenues** (line 1 + line 4)	228.4	307.5	491.0	237.4	251.1	246.5	245.0	257.4	223.6
8	**Bruce Costs** (line 2 + line 5)	222.3	202.2	315.2	303.4	317.3	320.9	330.8	339.5	316.8
9	**Bruce Lease Net Revenues** (line 7 - line 8)	6.1	105.3	175.8	(66.0)	(66.1)	(74.3)	(85.9)	(82.1)	(93.1)

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit G2
Tab 2
Schedule 1
Table 5

Table 5
Bruce Costs ($M)

Line No.	Cost Item	2013 Actual[1]	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	**Depreciation**	104.5	104.0	102.9	100.9	100.8	100.8	100.8	100.7	100.7
2	**Property Tax**	11.6	11.6	12.4	12.0	13.0	13.3	13.6	14.0	15.1
3	**Accretion**	369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
4	**(Earnings) Losses on Segregated Funds**	(337.1)	(411.8)	(338.6)	(379.8)	(395.7)	(413.7)	(432.8)	(454.8)	(479.8)
5	**Used Fuel Storage and Disposal**	54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
6	**Waste Management Variable Expenses and Facilities Removal Costs**	2.8	3.9	4.1	2.5	2.1	2.6	2.4	2.9	4.1
7	**Interest**	20.2	18.6	15.0	18.4	21.1	24.1	26.7	26.8	25.8
8	**Total Costs Before Income Tax**	225.0	171.9	261.4	330.1	344.0	350.4	359.5	366.8	347.8
9	**Income Tax - Current - Non-Derivative Portion**	26.9	56.9	61.0	43.8	38.2	26.3	9.1	(17.7)	(21.4)
10	**Income Tax - Deferred - Non-Derivative Portion**	(21.4)	(37.7)	(63.4)	(70.5)	(65.0)	(55.8)	(37.8)	(9.7)	(9.6)
11	**Total Income Tax - Non-Derivative Portion**	5.5	19.2	(2.4)	(26.7)	(26.8)	(29.5)	(28.6)	(27.4)	(31.0)
12	**Total Non-Derivative Costs** (line 8 + line 11)	230.5	191.1	259.0	303.4	317.3	320.9	330.8	339.5	316.8
13	**Income Tax - Current - Derivative Portion**	(26.9)	(0.6)	(19.2)	0.0	0.0	0.0	0.0	0.0	0.0
14	**Income Tax - Deferred - Derivative Portion**	18.7	11.7	75.4	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Income Tax - Derivative Portion[2]**	(8.2)	11.2	56.2	0.0	0.0	0.0	0.0	0.0	0.0
16	**Total Costs** (line 12 + line 15)	222.3	202.2	315.2	303.4	317.3	320.9	330.8	339.5	316.8

Note:
1 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Attachment 1, Table 36.
2 As discussed in Ex. G2-2-1, section 4.1.2, the derivative embedded in the Bruce lease agreement was reversed in 2015 following the December 2015 amendments to the agreement, which included the removal of the supplemental rent rebate provision giving rise to the embedded derivative.

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit C2
Tab 1
Schedule 1
Table 1

Table 1
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2013 to 2021

Line No.	Description	Note or Reference	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)
	PRESCRIBED FACILITIES										
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 2	80.7	80.7	80.7	50.3	50.3	50.3	50.3	50.3	18.7
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 2	49.0	53.6	53.1	62.0	53.0	55.2	66.7	56.3	56.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 2	3.3	2.1	2.0	3.2	4.8	4.5	5.4	5.6	6.5
	Return on ARC in Rate Base:										
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C1-1-1 Tables 1-9	78.9	74.6	70.3	42.2	39.6	37.1	34.5	31.9	30.2
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		212.0	211.0	206.1	157.6	147.7	147.1	158.9	144.1	111.9
7	**Income Tax Impact**	Note 2	38.0	13.6	11.1	(6.3)	(2.8)	(9.4)	(36.3)	36.3	25.6
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		249.9	224.6	217.2	151.3	144.9	137.7	120.6	180.4	137.5
	BRUCE FACILITIES										
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 3	101.2	100.4	100.4	100.2	100.2	100.2	100.2	100.2	100.2
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 3	54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 3	2.8	1.5	1.5	2.5	2.1	2.6	2.4	2.9	4.1
12	**Accretion Expense**	Ex. C2-1-1 Table 3	369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 3	337.1	411.8	338.6	379.8	395.7	413.7	432.8	454.8	479.8
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(47.5)	(33.9)	(57.2)	(74.8)	(77.3)	(78.1)	(79.6)	(81.4)	(76.6)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		142.4	101.7	171.7	224.3	232.0	234.3	238.9	244.2	229.8
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	Note 4	47.5	33.9	57.2	74.8	77.3	78.1	79.6	81.4	76.6
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		189.9	135.7	228.9	299.0	309.4	312.4	318.5	325.6	306.5
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites**		439.8	360.3	446.1	450.3	454.3	450.1	439.1	506.0	444.0
	(line 8 + line 17)										

Notes:

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

Chart 1

Summary of Revenue Requirement Impact of Nuclear Liabilities ($M)

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	Pre-Tax Revenue Requirement Impact	Ex. N1-1-1 Table 2, line 6	167.1	162.6	173.4	158.2	89.1	750.5
2	Regulatory Income Tax Impact of Nuclear Liabilities Costs and Segregated Fund Contributions	Ex. N1-1-1 Table 2, line 7	55.7	54.2	57.8	52.7	29.7	250.2
3	Revenue Requirement Impact of Nuclear Liabilities Costs *(Ex. N1-1-1 Table 2, line 8)*	line 1 + line 2	222.8	216.8	231.2	211.0	118.8	1,000.6
4	Regulatory Income Tax Impact of Nuclear Liabilities Expenditures and Segregated Fund Disbursements	Ex. N1-1-1 Chart 3.2.1, line 17	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)	(214.2)
5	Total Revenue Requirement Impact - Prescribed Facilities	line 3 + line 4	178.4	169.4	193.8	167.1	77.7	786.4
	Bruce Facilities							
6	Pre-Tax Revenue Rrequirement Impact (Impact on Bruce Lease Net Revenues)	Ex. N1-1-1 Table 2, line 15	156.4	150.4	153.1	157.7	148.6	766.2
7	Regulatory Income Tax Impact	Ex. N1-1-1 Table 2, line 16	52.1	50.1	51.0	52.6	49.5	255.4
8	Total Revenue Requriement Impact - Bruce Facilities *(Ex. N1-1-1 Table 2, line 17)*	line 6 + line 7	208.6	200.5	204.1	210.3	198.1	1,021.6
	Total Nuclear Liabilities							
9	Total Pre-Tax Revenue Requirement Impact	line 1 + line 6	323.5	313.0	326.5	315.9	237.7	1,516.7
10	Total Regulatory Income Tax Impact	line 2 + line 4 + line 7	63.5	56.9	71.4	61.4	38.1	291.3
11	Total Revenue Requirement Impact - Prescribed and Bruce Facilities	line 9 + line 10	387.0	369.9	397.9	377.4	275.8	1,808.0

As at December 31, 2016, the Decommissioning Segregated Fund ("DF") was overfunded at approximately 121% and the Used Fuel Segregated Fund ("UFF") was marginally overfunded at less than 1%, relative to the corresponding funding obligations per the 2017 ONFA Reference Plan. As reflected in Ex. N1-1-1, OPG expects this to result in overall zero required contributions to both funds until the next ONFA reference plan is approved. OPG submitted a proposed contribution schedule based on the 2017 ONFA Reference Plan to the Province on January 30, 2017 and is currently awaiting the Province's approval.

Consistent with OPG's 2017-2019 Business Plan, Ex. N1-1-1 reflected a zero contribution to the segregated funds for each of prescribed facilities and Bruce facilities starting in 2017. However, although each of the segregated funds is fully funded in aggregate, the portion of the 2017 ONFA Reference Plan funding obligations related to the prescribed facilities is underfunded, while the portion related to the Bruce facilities is overfunded.[2] OPG expects that, over time, the funds will need to be fully funded at a station level, consistent with the intent of the ONFA. As such, OPG's proposed contribution schedule based on the 2017

[2] Specifically, the prescribed facilities' portion of the DF is underfunded and the Bruce facilities' portion is overfunded; the reverse is true for the UFF.

As shown at line 14 of Ex. N1-1-1, Tables 3 and 4, OPG's 2017-2019 Business Plan assumed that the segregated fund contributions for each of the prescribed facilities and Bruce facilities will be zero for 2017 to 2021. Compared to the pre-filed evidence based on the 2012 ONFA Reference Plan (Ex. C2-1-1 Table 2, line 14), this represents a reduction in contributions of $667.5M for the prescribed facilities over the 5-year period, which increases the revenue requirement by $222.5.[26] This increase is reflected in the overall 5-year net increase of $279.6M in the prescribed facilities' portion of the nuclear liabilities revenue requirement outlined in Ex. N1-1-1.

The Bruce facilities' contributions for 2017-2021 are assumed to decrease by $242.5M per the 2017 ONFA Reference Plan, compared to the 2012 ONFA Reference Plan (Ex. C2-1-1 Table 3, line 14). While this does not impact the tax expense component of the Bruce Lease net revenues as discussed previously, it does have a modest secondary effect of reducing the forecast segregated fund earnings (net of deferred income taxes) due to a lower fund base, thereby increasing the revenue requirement. The forecast segregated fund earnings are lower by an average of approximately $3.5M/yr over the 2017-2021 period. This increase is reflected in the overall 5-year net decrease of $550.8M in the Bruce facilities' portion of the nuclear liabilities revenue requirement outlined in Ex. N1-1-1.

OPG is awaiting the Province's approval of the proposed contribution schedule based on the 2017-2021 ONFA Reference Plan, which OPG submitted on January 30, 2017. If approved, the schedule will result in overall positive contribution amounts for the prescribed facilities and offsetting overall negative contribution amounts for the Bruce facilities for the 2017-2021 period, in recognition that the prescribed facilities are in a net underfunded position and the Bruce facilities are in a net overfunded position. This would ensure that the funds are fully funded at a station level, consistent with the intent of the ONFA. Contributions based on OPG's proposed schedule would reduce the revenue requirement impact relative to Ex. N1-1-1, due to the tax benefit of the additional contributions for the prescribed facilities, partially

[26] Calculated as: $667.5M reduction in prescribed facilities' fund contributions x 25% / (1-25%).

offset by the impact of lower segregated fund earnings for the Bruce facilities as a result of the lower contributions. As noted above, the level of contributions for the Bruce facilities would not change the related income tax expense component of Bruce Lease net revenues.

Any differences between actual contributions as approved by the Province and the assumed amounts reflected in Ex. N1-1-1 will be subject to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

5.0 Amounts Collected from Ratepayers Versus Amounts Expended by OPG

5.1 Amounts Collected Versus Amounts Expended

Chart 3 below presents a comparison of estimated nuclear liabilities costs collected from ratepayers (or recorded in deferral and variance accounts for future disposition), before taxes, and amounts expended by OPG on nuclear liabilities in the form of fund contributions and internally funded expenditures. Chart 3 shows this information for each of prescribed facilities and Bruce facilities during the period from April 1, 2008 to December 31, 2016. For the prescribed facilities, the information is based on OEB-approved forecast amounts from previous proceedings, as adjusted for differences between actual and forecast nuclear production that affected the ultimate amount recovered, as well as amounts recorded in the Nuclear Liability Deferral Account and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account. For the Bruce facilities, the information shows the portion of actual Bruce Lease net revenues attributable to nuclear liabilities, which is what OPG ultimately recovers once forecast amounts are trued up through the Bruce Lease Net Revenues Variance Account. The comparison indicates that the total estimated amounts recovered over the period, before taxes, are lower than amounts expended for the prescribed facilities by approximately $41M and by approximately $241M for the Bruce facilities, for a total of approximately $282M.

Chart 3

Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)

April 1, 2008 to December 31, 2016

Line No.	Description	Apr 1 to Dec 31 2008	2009	2010	Jan 1 to Feb 28 2011	Mar 1 to Dec 31 2011	2012	2013	Jan 1 to Oct 31 2014	Nov 1 to Dec 31 2014	2015	2016	Total
	Prescribed Facilities												
1	Pre-tax Revenue Requirement Impact	159.4	207.4	209.6	34.9	121.4	145.6	145.7	121.4	35.8	213.2	213.9	1,608.2
2	(Under)/Over Recovery Due to Differences Between Approved and Actual Nuclear Production	(12.1)	(15.0)	(19.1)	1.7	(7.6)	(5.6)	(17.9)	(7.6)	1.2	(14.7)	(10.0)	(106.6)
3	Nuclear Liability Deferral Account	0.0	0.0	0.0	0.0	0.0	146.3	80.9	66.9	0.0	0.0	2.2	296.3
4	Impact of Changes in Station End-of-Life (2015) Deferral Account	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(49.1)	(49.1)
5	Total Amounts Recovered (pre-tax) (lines 1 through 4)	147.4	192.4	190.5	36.6	113.8	286.3	208.6	180.7	37.0	198.5	157.0	1,748.8
6	Contributions to Segregated Funds	44.2	124.7	150.2	24.2	120.8	107.1	98.1	141.6	28.5	172.8	176.7	1,188.9
7	Internally Funded Expenditures on Nuclear Liabilities	32.1	63.6	60.2	11.3	57.4	73.9	60.0	45.1	21.7	85.1	90.3	600.7
8	Total Amounts Expended (line 6 + line 7)	76.3	188.3	210.4	35.5	178.2	181.0	158.1	186.7	50.2	257.9	267.0	1,789.6
9	Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax) (line 5 - line 8)	71.1	4.1	(19.9)	1.2	(64.4)	105.3	50.5	(6.0)	(13.2)	(59.4)	(110.0)	(40.9)
	Bruce Facilities												
10	Actual Bruce Lease Net Revenues Impact	311.5	(32.6)	(68.6)	(8.5)	89.5	70.5	142.4	81.2	20.5	173.6	231.6	1,011.2
11	Contributions to Segregated Funds	296.2	214.1	113.9	17.6	87.9	74.9	85.9	(26.2)	(5.1)	(29.4)	(26.9)	802.9
12	Internally Funded Expenditures on Nuclear Liabilities	34.9	23.8	19.3	6.6	37.5	55.6	59.6	41.2	19.4	50.7	101.0	449.6
13	Total Amounts Expended (line 11 + line 12)	331.1	237.9	133.2	24.2	125.4	130.5	145.5	15.0	14.3	21.3	74.1	1,252.5
		226.8	164.2	94.6	17.8	92.2	97.9	109.1	11.3	10.7	16.0	55.6	896.0
14	Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax) (line 10 - line 13)	(19.6)	(270.5)	(201.8)	(32.7)	(35.9)	(60.0)	(3.0)	66.2	6.2	152.4	157.5	(241.3)
15	Total Excess of Amounts Recovered over Amounts Expended (pre-tax) (line 9 + line 14)	51.5	(266.4)	(221.7)	(31.5)	(100.3)	45.3	47.5	60.2	(7.0)	92.9	47.5	(282.1)

Presented in Chart 4 below is a comparison of proxy amounts collected from ratepayers through interim rates set by the Province and amounts expended by OPG, for the period from April 1, 2005 to March 31, 2008. As a proxy for amounts collected, this comparison uses actual values for the period available from the EB-2007-0905 proceeding,[27] applying the revenue requirement methodology accepted by the OEB in that proceeding as having been used by the Province to set interim rates.[28] This comparison indicates that, before taxes, OPG's contributions to the segregated funds and expenditures on internally funded nuclear liabilities costs for the period would have been in the order of $1B greater than proxy amounts recovered from ratepayers.

---

[27] Estimated amounts collected from ratepayers include those recorded in the Nuclear Liability Deferral Account for the period from January 1, 2007 to March 31, 2008. For the first quarter of 2008, estimated amounts are based on actual information available from the EB-2010-0008 proceeding.

[28] See EB-2007-0905 Decision With Reasons, pp. 97-98.

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

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.

Board Staff Interrogatory #169

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

Interrogatory

Reference:
Ref: Exh F3-1-1 page 14
Ref: EB-2010-0008 Exh F5-3-2

Figure 1 on page 14 presents a summary of corporate cost benchmarking results.

a) Are the peer results at column (c) at 2014?

b) In EB-2010-0008, OPG filed a Finance benchmarking report prepared by the Hackett Group. The report included reporting by peer group quartiles. What was OPG's performance by quartile for each corporate function in 2010 and 2014?

c) For the 2017-2021 test period, please provide IT cost per end user, HR cost per employee, finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue.

Response

a) As shown in Ex. F3-1-1, Attachment 1, p. 6, all data is represented in 2014 Canadian Dollars for comparison purposes.
   - PPP (Purchasing Power Parity) was used to adjust the peer data from US to Canadian Dollars
   - A 2%/year inflation rate was applied to the peer companies and OPG's 2010 costs/revenue to normalize the data to 2014 Canadian Dollars

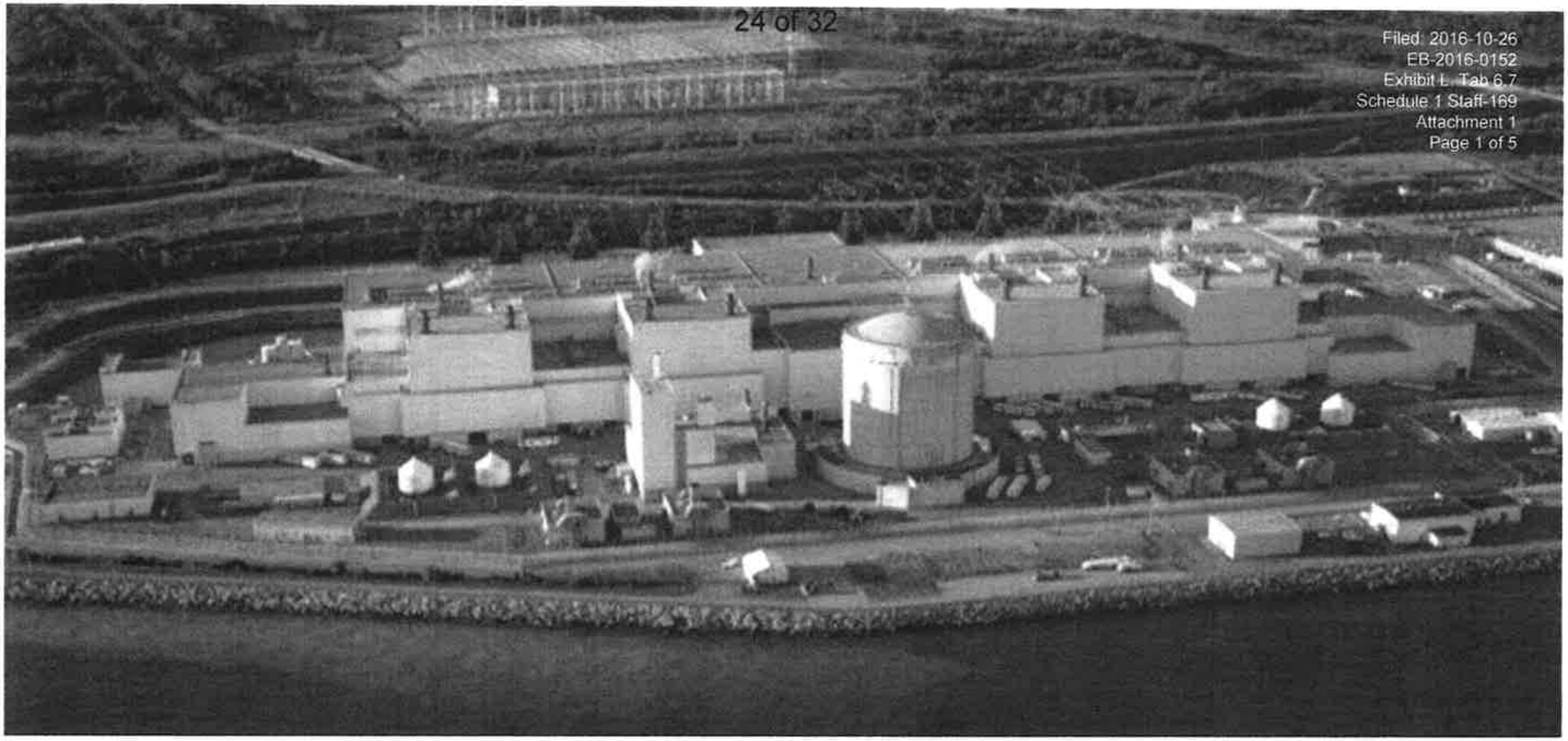
b) Attachment 1 to this response is OPG's performance by quartile as provided by the Hackett Group. Note, Attachment 1 is marked "confidential", however, OPG has determined this attachment to be non-confidential in its entirety.

c) Referring to the 2014 values at Ex. F3-1-1, Attachment 1, and forecasted corporate costs in Ex. F3-1-1, OPG has completed a high level estimate of the HR cost per employee, finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue for OPG's nuclear business for 2017-2021, as illustrated in Chart 1 below. IT cost per end user is not included as OPG does not forecast end users.

   Chart 1: Estimate of 2017-2021 HR cost per employee, Finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue, for OPG's nuclear business.

	2017	2018	2019	2020	2021
HR per employee	$2,659	$2,661	$2,695	$2,781	$2,839
ECS as a %	2.84	2.85	2.95	2.58	2.81
Finance as a %	0.78	0.78	0.81	0.71	0.77

OPG notes that the values indicated in Chart 1 above represent an estimate based on information available to OPG, and have not been derived using the Hackett Group's taxonomy applied to 2010 and 2014 costs, or otherwise vigorously vetted by a similar taxonomy, as this is not an exercise OPG performs in its normal course of business.



The Hackett Group
World Class Defined and Enabled

ONTARIO POWER GENERATION

Benchmarking Study of OPG's Corporate Support Functions and Costs – Quartile Data

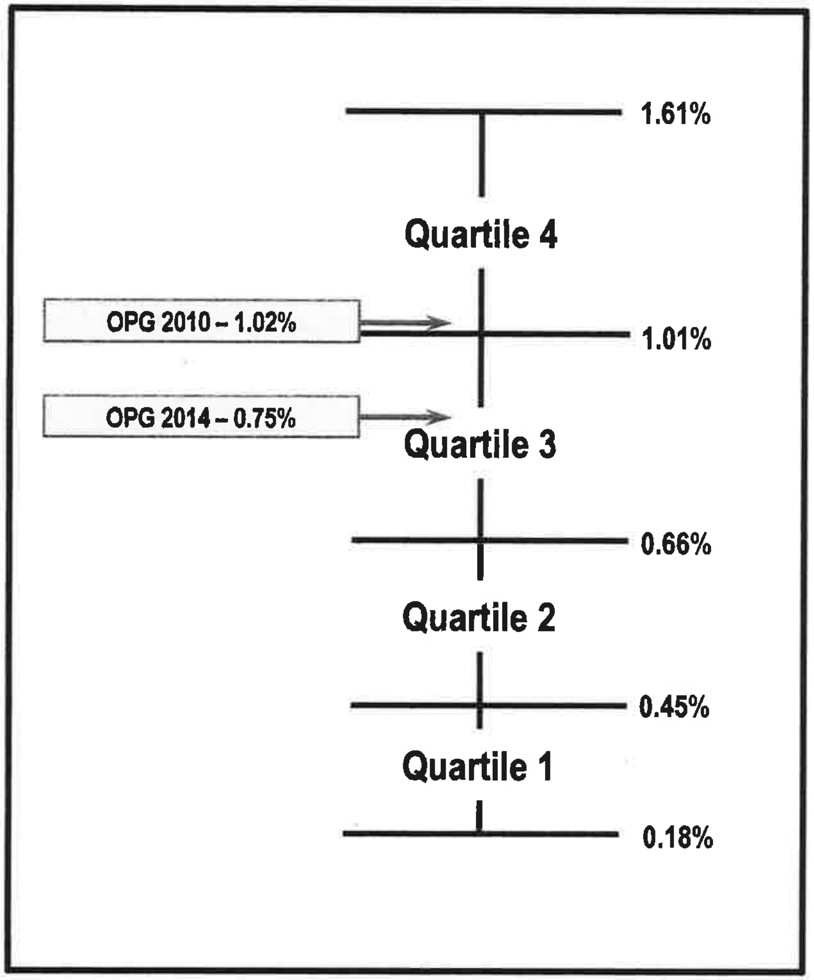
September 2016

CONFIDENTIAL

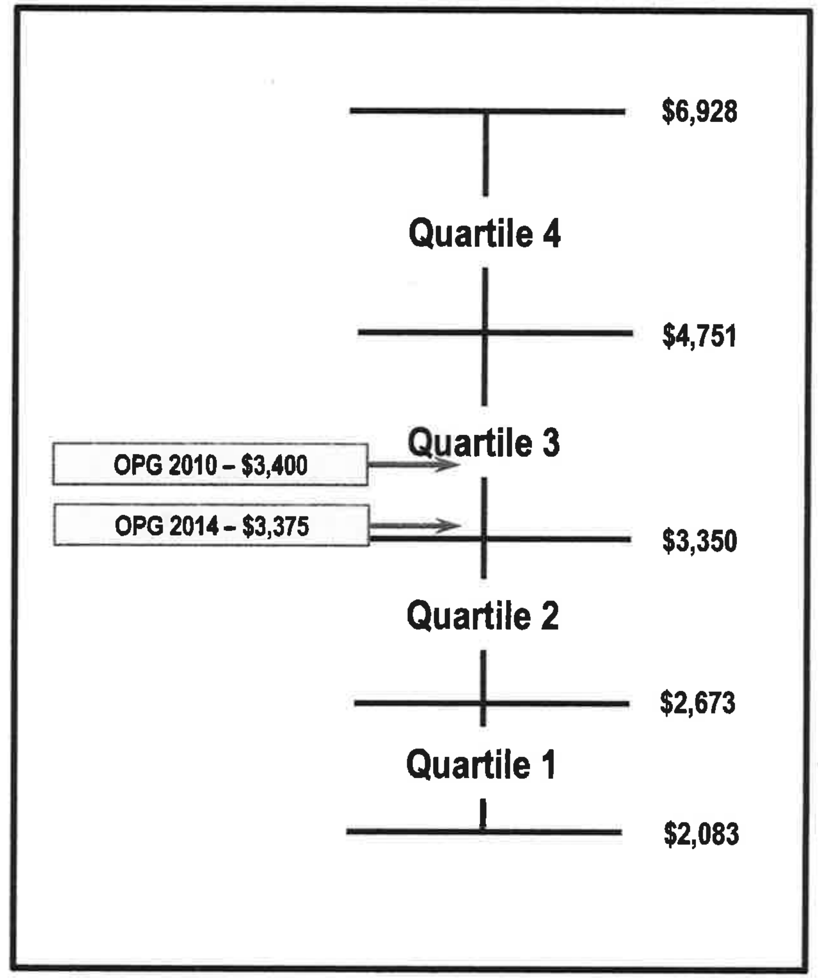
Filed: 2016-10-26
EB-2016-0152
Exhibit L, Tab 6.7
Schedule 1 Staff-169
Attachment 1
Page 2 of 5

Finance and HR Quartile Data

Finance Cost as a % of revenue



HR Cost per employee

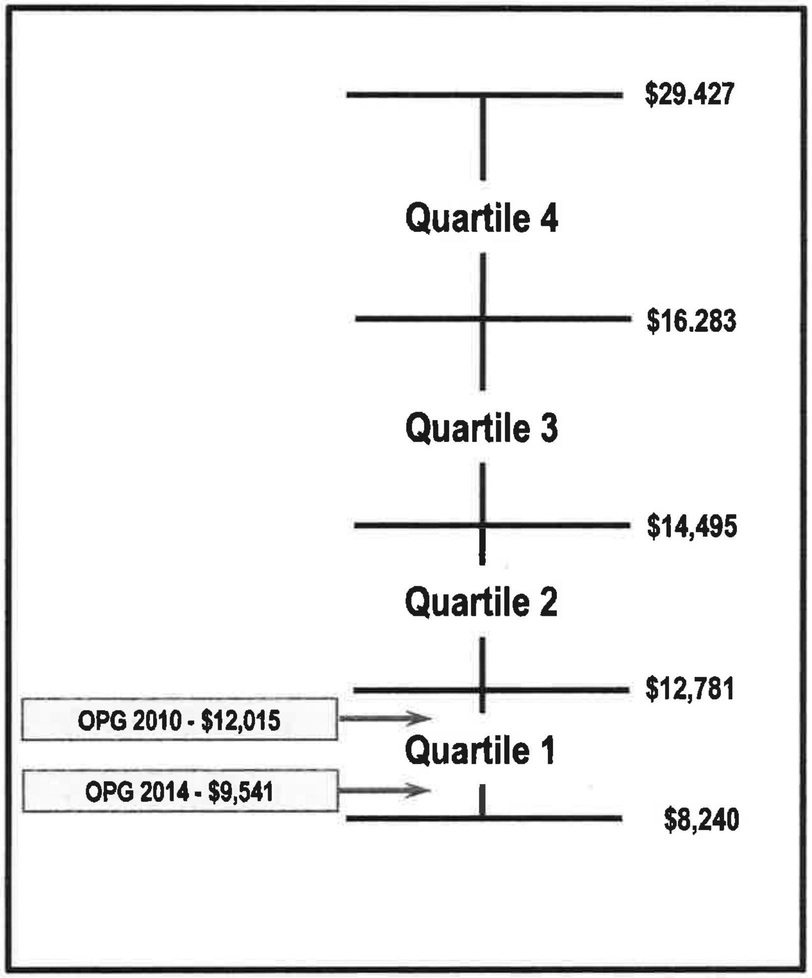


The Hackett Group

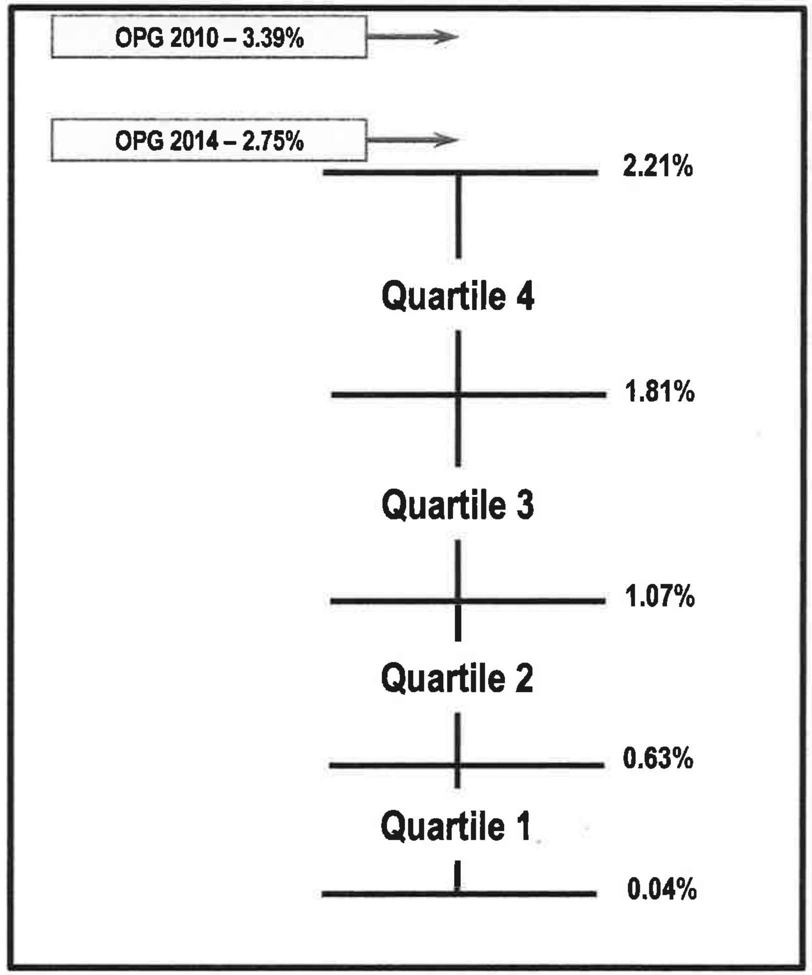
Filed: 2016-10-26
EB-2016-0152
Exhibit L, Tab 6.7
Schedule 1 Staff-169
Attachment 1
Page 3 of 5

IT and ECS Quartile Data

IT Cost Per End User



ECS Cost as a % of revenue



The Hackett Group

Filed: 2016-10-26
EB-2016-0152
Exhibit L, Tab 6.7
Schedule 1 Staff-169
Attachment 1
Page 4 of 5

Contact information

For information on this material, please contact:

John Philips
Project Director
jphilips@thehackettgroup.com

Sarah Clark
Benchmark Advisor
sclark@thehackettgroup.com

For other company information, please contact us under:

The Hackett Group
+1 866 442 2538
Email: info@thehackettgroup.com
www.thehackettgroup.com

The Hackett Group: Atlanta Office
1000 Abernathy Road NW, Suite 1400, Atlanta, GA 30328,
+1 866 442 2538
+1 770 225 3600

The Hackett Group: Frankfurt Office
Torhaus Westhafen
Speicherstraße 59
60327 Frankfurt am Main
+49 69 900 217 0

The Hackett Group: London Office
Martin House
5 Martin Lane
London EC4R 0DP
Phone: +44 20 7398 9100

Statement of Confidentiality and Usage Restrictions

The Hackett Group

The Hackett Group

World Class Defined and Enabled

www.thehackettgroup.com

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).

Filed: 2016-10-26
EB-2016-0152
Exhibit L
Tab 6.7
Schedule 6 EP-026
Attachment 1
Page 1 of 1

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

Line		2013 Actual		2014 Actual		2015 Actual		2016 Budget		2017 Plan		2018 Plan		2019 Plan		2020 Plan		2021 Plan	
No.	Corporate Group	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated	Dir. Assigned	Allocated
1	**Business and Administrative Service**	229.4	17.2	211.5	15.7	215.4	15.6	229.9	15.1	230.4	15.7	223.8	15.3	225.4	15.6	226.4	15.9	230.1	16.0
2	**Finance**	29.3	17.0	28.9	15.5	15.8	19.8	16.7	23.5	16.9	24.6	16.2	23.2	15.9	23.1	16.0	22.8	17.1	22.8
3	**People and Culture**	75.2	16.4	76.7	21.5	73.1	22.7	72.0	20.4	74.6	21.6	73.8	21.5	75.9	21.9	76.2	22.3	77.5	23.0
4	**Commercial Operations and Environment**	11.4	3.3	16.6	2.9	13.2	3.6	16.5	3.9	15.9	4.3	14.6	4.3	15.4	4.5	15.1	4.5	17.3	4.5
5	**Corporate Centre**	6.6	22.6	7.4	19.5	15.7	23.9	21.9	22.4	23.0	21.9	22.7	21.8	22.9	22.1	23.4	22.4	22.1	23.7
6	**Total**	351.9	76.5	341.1	75.1	333.2	85.6	357.0	85.3	360.8	88.1	351.1	86.1	355.5	87.2	357.1	87.9	364.1	90.0

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4
Tab 4
Schedule 1
Table 3

Table 3
Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	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	**Pension/OPEB Related Accrual Costs**	289.0	298.5	343.0	200.1	106.6	65.9	42.9	26.5	16.8
2	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences**[1]	0.0	0.0	0.0	0.0	(145.4)	(82.1)	(59.5)	(65.7)	(49.8)
3	**OPG-Wide Insurance**	3.3	3.4	4.6	6.2	6.4	6.5	7.0	7.0	6.8
4	**Nuclear Insurance**	7.6	8.0	8.2	19.1	21.1	23.1	26.1	26.5	27.1
5	**Performance Incentives**	14.5	20.2	17.1	18.4	18.4	18.5	18.6	18.5	18.5
6	**IESO Non-Energy Charges**	57.4	51.2	77.7	62.1	61.1	56.5	51.8	54.5	42.0
7	**Other**	38.1	29.7	9.4	21.0	6.7	24.5	16.0	18.3	14.3
8	**Total**	409.9	411.0	459.9	326.9	74.9	112.9	102.9	85.7	75.7

Notes:

1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the test period adjustment is included to reflect OPG's proposal to include cash amounts for pension and OPEB in the nuclear revenue requirement and defer the difference between accrual costs and cash amounts in the Pension & OPEB Cash to Accrual Differential Deferral Account pending the outcome of the EB-2015-0040 generic consultation, consistent with the EB-2013-0321 treatment.
The difference between accrual costs and cash amounts is found in Ex. F4-3-2 Chart 3.