Board Staff Interrogatory #001

Ref:

Issue Number: 1.0
Issue: General

Interrogatory

Revenue Requirement Work Form
OPG filed its application for 2014-2015 payment amounts on September 27, 2013. A Revenue Requirement Work Form ("RRWF") was filed with the application. On December 6, 2013, OPG filed an impact statement that revised the revenue requirement and the payment amounts. Another version of the RRWF was filed with the impact statement, in which the September 27, 2013 data were replaced.

Please combine both versions of the RRWF by revising the original RRWF. Please insert additional columns. For some tables 2 additional columns are required and for some tables 3 additional columns are required. The current "2014 OPG Proposed" column would be renamed "2014 OPG Proposed 27/9/13" and a new column "2014 OPG Proposed 6/12/13" would be inserted.

Please file the revised and completed RRWF in PDF and working Excel versions.

Response

The RRWF, revised as requested, is provided in PDF form as Attachment 1 to this response. An Excel version has been filed via RESS.

As requested, the updated version includes two separate columns that contain OPG financial projections. The first, titled "OPG Proposed 27/9/13", contains the financial projections presented in the initial September 27, 2013 filing.

The second column, titled "OPG Proposed 6/12/13", contains the updated financial projections presented within Ex. N1-1-1, as well as additional detailed Income Tax calculation inputs (in the form of both additions and deductions to Income Tax Adjustments) that were not included in the RRWF filed with Ex. N1-1-1.

In the December 6, 2013 filing the change to income tax amounts shown in Ex N1-1-1, Chart 9 were simply included as additions to the relevant Regulatory Income Tax lines of worksheet #7, OPG Revenue Requirement. This simplification did not affect the overall outcome in that the RRWF that accompanied Ex.N1-1-1 contains the identical revenue requirement, payment amounts, riders and consumer impact information as found within other tables filed with Ex N1-1-1 as well as the updated RRWF provided in this response.

Updated for Board Staff Interrogatory #1

EB-2013-0321
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

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Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

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OEB Adjustment Input Sheet

Line No.	Description	Total Generating Facilities 2014 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	2015 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Capital Structure								
1	Common Equity	47.0%	47.0%	0.0%	47.0%	47.0%	47.0%	0.0%	47.0%
2	Debt	53.0%	53.0%	0.0%	53.0%	53.0%	53.0%	0.0%	53.0%
	Cost of Capital								
3	Short-Term Debt Facility Cost ($M)	3.8	3.8	-	3.8	3.8	3.8	-	3.8
4	Short-Term Debt Interest Cost ($M)	4.0	4.0	-	4.0	6.2	6.2	-	6.2
5	Short-Term Debt Cost ($M)	7.0	7.0	-	7.0	9.0	9.0	-	9.0
6	Regulated Portion of Short-Term Debt Cost Rate	89.41%	89.41%	0.00%	89.41%	89.41%	89.41%	0.00%	89.41%
7	Existing and Planned Long-Term Debt Cost Rate	4.85%	4.85%	0.00%	4.85%	4.86%	4.86%	0.00%	4.86%
8	Other Long-Term Debt Provision Cost Rate	4.85%	4.85%	0.00%	4.85%	4.86%	4.86%	0.00%	4.86%
9	Common Equity Cost Rate ROE	8.98%	8.98%	0.00%	8.98%	8.98%	8.98%	0.00%	8.98%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.37%	5.37%	0.00%	5.37%	5.37%	5.37%	0.00%	5.37%
	Capitalization ($M)								
11	Short-Term Debt Principal	192.2	192.2	-	192.2	192.2	192.2	-	192.2
12	Existing and Planned Long-Term Debt Principal	3,372.7	3,372.7	-	3,372.7	3,481.6	3,481.6	-	3,481.6
13	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	-	1,308.8

Line No.	Description	Previously Regulated Hydroelectric Facilities 2014 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	2015 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	Total OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate Base ($M)												
14	Gross Plant at Cost	6,079.9	6,079.9	-	6,079.9	6,118.4	6,118.4	-	6,118.4	12,198.3	12,198.3	-	12,198.3
15	Accumulated Depreciation/Amortization	974.3	974.3	-	974.3	1,056.2	1,056.2	-	1,056.2	2,030.5	2,030.5	-	2,030.5
16	Cash Working Capital	21.7	21.7	-	21.7	21.7	21.7	-	21.7	43.4	43.4	-	43.4
17	Materials and Supplies	0.7	0.7	-	0.7	0.7	0.7	-	0.7	1.4	1.4	-	1.4
18	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	**Total**	**5,128.0**	**5,128.0**	**-**	**5,128.0**	**5,084.6**	**5,084.6**	**-**	**5,084.6**	**10,212.6**	**10,212.6**	**-**	**10,212.6**
	Expenses ($M)												
20	OM&A	145.5	149.2	-	149.2	141.1	144.2	-	144.2	286.5	293.5	-	293.5
21	GRC	253.3	267.2	-	267.2	269.5	280.8	-	280.8	522.8	548.0	-	548.0
22	Depreciation/Amortization	82.1	82.1	-	82.1	81.9	81.9	-	81.9	164.0	164.0	-	164.0
23	Property Taxes	0.3	0.3	-	0.3	0.3	0.3	-	0.3	0.6	0.6	-	0.6
24	**Total**	**481.1**	**498.8**	**-**	**498.8**	**492.9**	**507.2**	**-**	**507.2**	**973.9**	**1,006.1**	**-**	**1,006.1**
	Other Revenues ($M)												
25	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Ancillary and Other Revenue	19.9	34.0	-	34.0	20.2	34.6	-	34.6	40.1	68.6	-	68.6
27	**Total**	**19.9**	**34.0**	**-**	**34.0**	**20.2**	**34.6**	**-**	**34.6**	**40.1**	**68.6**	**-**	**68.6**
28	**Forecast Production** (TWh)	**19.1**	**20.1**	**-**	**20.1**	**20.2**	**21.0**	**-**	**21.0**	**39.3**	**41.1**	**-**	**41.1**

OEB Adjustment Input Sheet

		Newly Regulated Hydroelectric Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate Base ($M)												
29	Gross Plant at Cost	3,275.1	3,275.1	-	3,275.1	3,347.7	3,347.7	-	3,347.7	6,622.9	6,622.9	-	6,622.9
30	Accumulated Depreciation/Amortization	772.6	772.6	-	772.6	828.5	828.5	-	828.5	1,601.2	1,601.2	-	1,601.2
31	Cash Working Capital	8.3	8.3	-	8.3	8.3	8.3	-	8.3	16.5	16.5	-	16.5
32	Materials and Supplies	0.7	0.7	-	0.7	0.7	0.7	-	0.7	1.4	1.4	-	1.4
33	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
34	**Total**	**2,511.5**	**2,511.5**	**-**	**2,511.5**	**2,528.2**	**2,528.2**	**-**	**2,528.2**	**5,039.7**	**5,039.7**	**-**	**5,039.7**
	Expenses ($M)												
35	OM&A	232.5	239.3	-	239.3	237.2	242.6	-	242.6	469.7	482.0	-	482.0
36	GRC	75.6	75.6	-	75.6	77.5	77.5	-	77.5	153.1	153.1	-	153.1
37	Depreciation/Amortization	62.2	62.2	-	62.2	63.1	63.1	-	63.1	125.3	125.3	-	125.3
38	Property Taxes	0.1	0.1	-	0.1	0.1	0.1	-	0.1	0.2	0.2	-	0.2
39	**Total**	**370.4**	**377.3**	**-**	**377.3**	**377.9**	**383.3**	**-**	**383.3**	**748.3**	**760.6**	**-**	**760.6**
	Other Revenues ($M)												
40	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
41	Ancillary and Other Revenue	22.7	22.7	-	22.7	23.1	23.1	-	23.1	45.8	45.8	-	45.8
42	**Total**	**22.7**	**22.7**	**-**	**22.7**	**23.1**	**23.1**	**-**	**23.1**	**45.8**	**45.8**	**-**	**45.8**
43	**Forecast Production**[1] (TWh)	**5.5**	**5.5**	**-**	**5.5**	**12.5**	**12.5**	**-**	**12.5**	**17.9**	**17.9**	**-**	**17.9**

		Nuclear Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate Base ($M)												
44	Gross Plant at Cost	6,262.8	6,262.8	-	6,262.8	6,510.7	6,510.7	-	6,510.7	12,773.5	12,773.5	-	12,773.5
45	Accumulated Depreciation/Amortization	3,299.0	3,299.0	-	3,299.0	3,580.1	3,580.1	-	3,580.1	6,879.1	6,879.1	-	6,879.1
46	Cash Working Capital	32.0	32.0	-	32.0	32.0	32.0	-	32.0	64.0	64.0	-	64.0
47	Materials and Supplies	427.2	427.2	-	427.2	422.0	422.0	-	422.0	849.2	849.2	-	849.2
48	Nuclear Fuel Inventory	283.6	283.6	-	283.6	274.4	274.4	-	274.4	558.0	558.0	-	558.0
49	**Total**	**3,706.7**	**3,706.7**	**-**	**3,706.7**	**3,659.0**	**3,659.0**	**-**	**3,659.0**	**7,365.7**	**7,365.7**	**-**	**7,365.7**
	Expenses ($M)												
50	OM&A	2,422.7	2,491.8	-	2,491.8	2,473.3	2,531.3	-	2,531.3	4,896.0	5,023.0	-	5,023.0
51	Fuel	280.5	268.6	-	268.6	267.9	260.5	-	260.5	548.4	529.0	-	529.0
52	Depreciation/Amortization	273.7	273.7	-	273.7	288.5	288.5	-	288.5	562.3	562.3	-	562.3
53	Property Taxes	15.9	15.9	-	15.9	16.4	16.4	-	16.4	32.4	32.4	-	32.4
54	**Total**	**2,992.8**	**3,050.0**	**-**	**3,050.0**	**3,046.3**	**3,096.7**	**-**	**3,096.7**	**6,039.1**	**6,146.7**	**-**	**6,146.7**
	Other Revenues ($M)												
55	Bruce Lease Revenues Net of Direct Costs	39.7	39.7	-	39.7	40.6	40.6	-	40.6	80.3	80.3	-	80.3
56	Ancillary and Other Revenue	33.2	33.2	-	33.2	30.5	30.5	-	30.5	63.7	63.7	-	63.7
57	**Total**	**72.9**	**72.9**	**-**	**72.9**	**71.1**	**71.1**	**-**	**71.1**	**144.0**	**144.0**	**-**	**144.0**
58	**Forecast Production** (TWh)	**49.7**	**49.0**	**-**	**49.0**	**48.0**	**46.1**	**-**	**46.1**	**97.7**	**95.1**	**-**	**95.1**

OEB Adjustment Input Sheet

		Total Generating Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate Base ($M)												
59	Gross Plant at Cost	15,617.8	15,617.8	-	15,617.8	15,976.9	15,976.9	-	15,976.9	31,594.7	31,594.7	-	31,594.7
60	Accumulated Depreciation/Amortization	5,045.9	5,045.9	-	5,045.9	5,464.8	5,464.8	-	5,464.8	10,510.7	10,510.7	-	10,510.7
61	Cash Working Capital	62.0	62.0	-	62.0	62.0	62.0	-	62.0	123.9	123.9	-	123.9
62	Materials and Supplies	428.6	428.6	-	428.6	423.4	423.4	-	423.4	852.0	852.0	-	852.0
63	Nuclear Fuel Inventory	283.6	283.6	-	283.6	274.4	274.4	-	274.4	558.0	558.0	-	558.0
64	**Total**	**11,346.1**	**11,346.1**	**-**	**11,346.1**	**11,271.8**	**11,271.8**	**-**	**11,271.8**	**22,617.9**	**22,617.9**	**-**	**22,617.9**
	Expenses ($M)												
65	OM&A	2,800.6	2,880.3	-	2,880.3	2,851.6	2,918.1	-	2,918.1	5,652.2	5,798.4	-	5,798.4
66	Fuel and GRC	609.3	611.4	-	611.4	615.0	618.8	-	618.8	1,224.3	1,230.2	-	1,230.2
67	Depreciation/Amortization	418.0	418.0	-	418.0	433.6	433.6	-	433.6	851.6	851.6	-	851.6
68	Property Taxes	16.3	16.3	-	16.3	16.8	16.8	-	16.8	33.2	33.2	-	33.2
69	**Total**	**3,844.3**	**3,926.1**	**-**	**3,926.1**	**3,917.0**	**3,987.3**	**-**	**3,987.3**	**7,761.3**	**7,913.4**	**-**	**7,913.4**
	Other Revenues ($M)												
70	Bruce Lease Revenues Net of Direct Costs	39.7	39.7	-	39.7	40.6	40.6	-	40.6	80.3	80.3	-	80.3
71	Ancillary and Other Revenue	75.7	89.8	-	89.8	73.8	88.2	-	88.2	149.5	178.0	-	178.0
72	**Total**	**115.4**	**129.5**	**-**	**129.5**	**114.4**	**128.8**	**-**	**128.8**	**229.8**	**258.3**	**-**	**258.3**
73	**Forecast Production** (TWh)	**74.2**	**74.6**	**-**	**74.6**	**80.7**	**79.6**	**-**	**79.6**	**154.9**	**154.2**	**-**	**154.2**

OEB Adjustment Input Sheet

Line No.	Description	Regulatory Income Taxes 2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Applicable Tax Rates								
74	Federal Rate	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%
75	Provincial Rate	11.00%	11.00%	0.00%	11.00%	11.00%	11.00%	0.00%	11.00%
76	Provincial Manufacturing & Processing Profits Deduction	-1.00%	-1.00%	0.00%	-1.00%	-1.00%	-1.00%	0.00%	-1.00%
77	**Total Tax Rate**	**25.00%**	**25.00%**	**0.00%**	**25.00%**	**25.00%**	**25.00%**	**0.00%**	**25.00%**
	Tax Credits and Payment Adjustments ($M)								
78	SR&ED Investment	(10.4)	(10.4)	-	(10.4)	(10.4)	(10.4)	-	(10.4)
79	Single Payments Amount Adjustment	12.3	12.3	-	12.3	(12.3)	(12.3)	-	(12.3)
	Taxable Income Adjustments ($M)								
	Additions								
80	Depreciation and Amortization	418.0	418.0	-	418.0	433.6	433.6	-	433.6
81	Nuclear Waste Management Expenses	59.3	59.3	-	59.3	62.2	62.2	-	62.2
82	Receipts from Nuclear Segregated Funds	62.6	62.6	-	62.6	116.5	116.5	-	116.5
83	Pension and OPEB/SPP Accrual	682.0	761.7	-	761.7	672.7	739.1	-	739.1
84	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	41.9	-	41.9	-	-	-	-
85	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	(12.4)	-	(12.4)	-	-	-	-
86	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	74.6	-	74.6	70.3	70.3	-	70.3
87	Taxable SR&ED Investment Tax Credits of Prior Periods	14.8	14.8	-	14.8	10.4	10.4	-	10.4
88	Other	45.9	45.9	-	45.9	49.7	49.7	-	49.7
89	**Total Additions**	**1,386.7**	**1,466.4**	**-**	**1,466.4**	**1,415.4**	**1,481.8**	**-**	**1,481.8**
	Deductions								
90	CCA	419.0	419.0	-	419.0	467.0	467.0	-	467.0
91	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	148.8	-	148.8	197.6	197.6	-	197.6
92	Contributions to Nuclear Segregated Funds	170.1	170.1	-	170.1	172.8	172.8	-	172.8
93	Pension Plan Contributions	238.0	355.3	-	355.3	340.2	401.8	-	401.8
94	OPEB/SPP Payments	99.7	89.3	-	89.3	106.5	95.8	-	95.8
95	Other	0.5	0.5	-	0.5	0.5	0.5	-	0.5
96	**Total Deductions**	**1,076.1**	**1,183.0**	**-**	**1,183.0**	**1,284.6**	**1,335.4**	**-**	**1,335.4**

Line No.	Description	Deferral and Variance Account Recovery 2015: Projected Balance at December 31, 2013 OPG Proposed 27/9/13	Projected Balance OPG Proposed 6/12/13	Projected Balance OEB Adjustment	Projected Balance OEB Approved	Recovery Period (Months) OPG Proposed 27/9/13	Recovery Period OPG Proposed 6/12/13	Recovery Period OEB Adjustment	Recovery Period OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Previously Regulated Hydroelectric Facilities ($M)								
97	Capacity Refurbishment Variance	114.4	114.4	-	114.4	24	24	-	24
98	Hydroelectric Incentive Mechanism Variance	(2.4)	(2.4)	-	(2.4)	12	12	-	12
99	Surplus Baseload Generation Variance	8.1	8.1	-	8.1	12	12	-	12
100	**Total**	120.1	120.1	-	120.1	n/a	n/a	n/a	n/a
	Nuclear Facilities ($M)								
101	Capacity Refurbishment Variance - Capital Portion	3.7	3.7	-	3.7	12	12	-	12
102	Nuclear Development Variance	69.4	69.4	-	69.4	12	12	-	12
103	**Total**	73.1	73.1	-	73.1	n/a	n/a	n/a	n/a

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

OPG Rate Base and Cost of Capital

Line No.	Description	Total Generating Facilities 2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Previously Regulated Hydroelectric Rate Base ($M)	5,128.0	5,128.0	-	5,128.0	5,084.6	5,084.6	-	5,084.6
2	Newly Regulated Hydroelectric Rate Base ($M)	2,511.5	2,511.5	-	2,511.5	2,528.2	2,528.2	-	2,528.2
3	Nuclear Rate Base Financed by Capital Structure ($M)	2,317.2	2,317.2	-	2,317.2	2,350.2	2,350.2	-	2,350.2
4	Previously Regulated Hydroelectric Allocation factor	51.50%	51.50%	0.00%	51.50%	51.03%	51.03%	0.00%	51.03%
5	Newly Regulated Hydroelectric Allocation Factor	25.22%	25.22%	0.00%	25.22%	25.38%	25.38%	0.00%	25.38%
6	Nuclear Allocation Factor	23.27%	23.27%	0.00%	23.27%	23.59%	23.59%	0.00%	23.59%

Line No.	Description	Previously Regulated Hydroelectric Facilities 2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed 27/9/13	Total OPG Proposed 6/12/13	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capitalization ($M)												
7	Total Rate Base	5,128.0	5,128.0	-	5,128.0	5,084.6	5,084.6	-	5,084.6	10,212.6	10,212.6	-	10,212.6
8	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	**Rate Base Financed by Capital Structure**	**5,128.0**	**5,128.0**	**-**	**5,128.0**	**5,084.6**	**5,084.6**	**-**	**5,084.6**	**10,212.6**	**10,212.6**	**-**	**10,212.6**
10	**Common Equity**	**2,410.1**	**2,410.1**	**-**	**2,410.1**	**2,389.8**	**2,389.8**	**-**	**2,389.8**	**4,799.9**	**4,799.9**	**-**	**4,799.9**
11	Total Debt	2,717.8	2,717.8	-	2,717.8	2,694.8	2,694.8	-	2,694.8	5,412.7	5,412.7	-	5,412.7
12	Short-Term Debt	99.0	99.0	-	99.0	98.1	98.1	-	98.1	197.1	197.1	-	197.1
13	Existing and Planned Long-Term Debt	1,737.0	1,737.0	-	1,737.0	1,776.8	1,776.8	-	1,776.8	3,513.8	3,513.8	-	3,513.8
14	**Other Long-Term Debt Provision**	**881.8**	**881.8**	**-**	**881.8**	**819.9**	**819.9**	**-**	**819.9**	**1,701.7**	**1,701.7**	**-**	**1,701.7**
	Cost of Capital ($M)												
15	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	**Common Equity**	**216.4**	**216.4**	**-**	**216.4**	**214.6**	**214.6**	**-**	**214.6**	**431.0**	**431.0**	**-**	**431.0**
17	Existing and Planned Long-Term Debt	84.2	84.2	-	84.2	86.4	86.4	-	86.4	170.6	170.6	-	170.6
18	Other Long-Term Debt Provision	42.8	42.8	-	42.8	39.8	39.8	-	39.8	82.6	82.6	-	82.6

Line No.	Description	Newly Regulated Hydroelectric Facilities 2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed 27/9/13	Total OPG Proposed 6/12/13	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capitalization ($M)												
19	Total Rate Base	2,511.5	2,511.5	-	2,511.5	2,528.2	2,528.2	-	2,528.2	5,039.7	5,039.7	-	5,039.7
20	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	**Rate Base Financed by Capital Structure**	**2,511.5**	**2,511.5**	**-**	**2,511.5**	**2,528.2**	**2,528.2**	**-**	**2,528.2**	**5,039.7**	**5,039.7**	**-**	**5,039.7**
22	**Common Equity**	**1,180.4**	**1,180.4**	**-**	**1,180.4**	**1,188.2**	**1,188.2**	**-**	**1,188.2**	**2,368.6**	**2,368.6**	**-**	**2,368.6**
23	Total Debt	1,331.1	1,331.1	-	1,331.1	1,339.9	1,339.9	-	1,339.9	2,671.0	2,671.0	-	2,671.0
24	Short-Term Debt	48.5	48.5	-	48.5	48.8	48.8	-	48.8	97.3	97.3	-	97.3
25	Existing and Planned Long-Term Debt	850.7	850.7	-	850.7	883.5	883.5	-	883.5	1,734.2	1,734.2	-	1,734.2
26	**Other Long-Term Debt Provision**	**431.9**	**431.9**	**-**	**431.9**	**407.7**	**407.7**	**-**	**407.7**	**839.6**	**839.6**	**-**	**839.6**
	Cost of Capital ($M)												
27	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	**Common Equity**	**106.0**	**106.0**	**-**	**106.0**	**106.7**	**106.7**	**-**	**106.7**	**212.7**	**212.7**	**-**	**212.7**
29	Existing and Planned Long-Term Debt	41.3	41.3	-	41.3	42.9	42.9	-	42.9	84.2	84.2	-	84.2
30	Other Long-Term Debt Provision	20.9	20.9	-	20.9	19.8	19.8	-	19.8	40.8	40.8	-	40.8

OPG Rate Base and Cost of Capital

Nuclear Facilities

Line No.	Description	2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed 27/9/13	Total OPG Proposed 6/12/13	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capitalization ($M)												
31	Total Rate Base	3,706.7	3,706.7	-	3,706.7	3,659.0	3,659.0	-	3,659.0	7,365.7	7,365.7	-	7,365.7
32	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	-	1,308.8	2,698.2	2,698.2	-	2,698.2
33	**Rate Base Financed by Capital Structure**	**2,317.2**	**2,317.2**	**-**	**2,317.2**	**2,350.2**	**2,350.2**	**-**	**2,350.2**	**4,667.4**	**4,667.4**	**-**	**4,667.4**
34	**Common Equity**	**1,089.1**	**1,089.1**	**-**	**1,089.1**	**1,104.6**	**1,104.6**	**-**	**1,104.6**	**2,193.7**	**2,193.7**	**-**	**2,193.7**
35	Total Debt	1,228.1	1,228.1	-	1,228.1	1,245.6	1,245.6	-	1,245.6	2,473.7	2,473.7	-	2,473.7
36	Short-Term Debt	44.7	44.7	-	44.7	45.3	45.3	-	45.3	90.1	90.1	-	90.1
37	Existing and Planned Long-Term Debt	784.9	784.9	-	784.9	821.3	821.3	-	821.3	1,606.2	1,606.2	-	1,606.2
38	**Other Long-Term Debt Provision**	**398.5**	**398.5**	**-**	**398.5**	**379.0**	**379.0**	**-**	**379.0**	**777.5**	**777.5**	**-**	**777.5**
	Cost of Capital ($M)												
39	Adjustment for Lesser of UNL/ARC	74.6	74.6	-	74.6	70.3	70.3	-	70.3	144.9	144.9	-	144.9
40	**Common Equity**	**97.8**	**97.8**	**-**	**97.8**	**99.2**	**99.2**	**-**	**99.2**	**197.0**	**197.0**	**-**	**197.0**
41	Existing and Planned Long-Term Debt	38.1	38.1	-	38.1	39.9	39.9	-	39.9	78.0	78.0	-	78.0
42	Other Long-Term Debt Provision	19.3	19.3	-	19.3	18.4	18.4	-	18.4	37.7	37.7	-	37.7

Total Generating Facilities

Line No.	Description	2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved	Total OPG Proposed 27/9/13	Total OPG Proposed 6/12/13	Total OEB Adjustment	Total OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Capitalization ($M)												
43	Total Rate Base	11,346.1	11,346.1	-	11,346.1	11,271.8	11,271.8	-	11,271.8	22,617.9	22,617.9	-	22,617.9
44	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	-	1,308.8	2,698.2	2,698.2	-	2,698.2
45	**Rate Base Financed by Capital Structure**	**9,956.7**	**9,956.7**	**-**	**9,956.7**	**9,963.0**	**9,963.0**	**-**	**9,963.0**	**19,919.7**	**19,919.7**	**-**	**19,919.7**
46	**Common Equity**	**4,679.6**	**4,679.6**	**-**	**4,679.6**	**4,682.6**	**4,682.6**	**-**	**4,682.6**	**9,362.2**	**9,362.2**	**-**	**9,362.2**
47	Total Debt	5,277.0	5,277.0	-	5,277.0	5,280.4	5,280.4	-	5,280.4	10,557.4	10,557.4	-	10,557.4
48	Short-Term Debt	192.2	192.2	-	192.2	192.2	192.2	-	192.2	384.4	384.4	-	384.4
49	Existing and Planned Long-Term Debt	3,372.7	3,372.7	-	3,372.7	3,481.6	3,481.6	-	3,481.6	6,854.2	6,854.2	-	6,854.2
50	**Other Long-Term Debt Provision**	**1,712.1**	**1,712.1**	**-**	**1,712.1**	**1,606.6**	**1,606.6**	**-**	**1,606.6**	**3,318.8**	**3,318.8**	**-**	**3,318.8**
	Cost of Capital ($M)												
51	Adjustment for Lesser of UNL/ARC	74.6	74.6	-	74.6	70.3	70.3	-	70.3	144.9	144.9	-	144.9
52	**Common Equity**	**420.2**	**420.2**	**-**	**420.2**	**420.5**	**420.5**	**-**	**420.5**	**840.7**	**840.7**	**-**	**840.7**
53	Existing and Planned Long-Term Debt	163.6	163.6	-	163.6	169.2	169.2	-	169.2	332.8	332.8	-	332.8
54	Other Long-Term Debt Provision	83.0	83.0	-	83.0	78.1	78.1	-	78.1	161.1	161.1	-	161.1

OPG Regulatory Income Taxes

Line No.	Description	Total Generating Facilities 2014 OPG Proposed 27/9/13	2014 OPG Proposed 6/12/13	2014 OEB Adjustment	2014 OEB Approved	2015 OPG Proposed 27/9/13	2015 OPG Proposed 6/12/13	2015 OEB Adjustment	2015 OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Applicable Tax Rates								
1	Federal Rate	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	11.00%	11.00%	0.00%	11.00%	11.00%	11.00%	0.00%	11.00%
3	Provincial Manufacturing & Processing Profits Deduction	-1.00%	-1.00%	0.00%	-1.00%	-1.00%	-1.00%	0.00%	-1.00%
4	**Total Tax Rate**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**
	Taxable Income ($M)								
5	Earnings Before Tax	613.5	604.4	-	604.4	519.8	525.0	-	525.0
6	Adjustments: Additions	1,386.7	1,466.4	-	1,466.4	1,415.4	1,481.8	-	1,481.8
7	Adjustments: Deductions	1,076.1	1,183.0	-	1,183.0	1,284.6	1,335.4	-	1,335.4
8	**Total Taxable Income**	**924.1**	**887.8**	**-**	**887.8**	**650.6**	**671.4**	**-**	**671.4**
	Income Taxes ($M)								
9	Federal Income Taxes	138.6	133.2	-	133.2	97.6	100.7	-	100.7
10	Provincial Income Taxes	92.4	88.8	-	88.8	65.1	67.1	-	67.1
11	Tax Credits (SR&ED Investment)	(10.4)	(10.4)	-	(10.4)	(10.4)	(10.4)	-	(10.4)
12	**Total Income Taxes**	**220.6**	**211.5**	**-**	**211.5**	**152.3**	**157.5**	**-**	**157.5**
	Earnings Before Tax ($M)								
13	**Requested After Tax ROE**	**420.2**	**420.2**	**-**	**420.2**	**420.5**	**420.5**	**-**	**420.5**
14	Bruce Lease Net Revenues	39.7	39.7	-	39.7	40.6	40.6	-	40.6
15	Income Taxes	220.6	211.5	-	211.5	152.3	157.5	-	157.5
16	Single Payments Amount Adjustment	12.3	12.3	-	12.3	(12.3)	(12.3)	-	(12.3)
17	**Total Earnings Before Tax**	**613.5**	**604.4**	**-**	**604.4**	**519.8**	**525.0**	**-**	**525.0**
	Adjustments ($M)								
	Additions								
18	Depreciation and Amortization	418.0	418.0	-	418.0	433.6	433.6	-	433.6
19	Nuclear Waste Management Expenses	59.3	59.3	-	59.3	62.2	62.2	-	62.2
20	Receipts from Nuclear Segregated Funds	62.6	62.6	-	62.6	116.5	116.5	-	116.5
21	Pension and OPEB/SPP Accrual	682.0	761.7	-	761.7	672.7	739.1	-	739.1
22	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	41.9	-	41.9	-	-	-	-
23	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	(12.4)	-	(12.4)	-	-	-	-
24	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	74.6	-	74.6	70.3	70.3	-	70.3
25	Taxable SR&ED Investment Tax Credits of Prior Periods	14.8	14.8	-	14.8	10.4	10.4	-	10.4
26	Other	45.9	45.9	-	45.9	49.7	49.7	-	49.7
27	**Total Additions**	**1,386.7**	**1,466.4**	**-**	**1,466.4**	**1,415.4**	**1,481.8**	**-**	**1,481.8**
	Deductions								
28	CCA	419.0	419.0	-	419.0	467.0	467.0	-	467.0
29	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	148.8	-	148.8	197.6	197.6	-	197.6
30	Contributions to Nuclear Segregated Funds	170.1	170.1	-	170.1	172.8	172.8	-	172.8
31	Pension Plan Contributions	238.0	355.3	-	355.3	340.2	401.8	-	401.8
32	OPEB/SPP Payments	99.7	89.3	-	89.3	106.5	95.8	-	95.8
33	Other	0.5	0.5	-	0.5	0.5	0.5	-	0.5
34	**Total Deductions**	**1,076.1**	**1,183.0**	**-**	**1,183.0**	**1,284.6**	**1,335.4**	**-**	**1,335.4**

OPG Revenue Requirement

Line No.	Description	Previously Regulated Hydroelectric Facilities											
		2014				2015				Total			
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Cost of Capital ($M)												
1	Short-term Debt	3.6	3.6	0.0	3.6	4.6	4.6	0.0	4.6	8.2	8.2	0.0	8.2
2	Long-Term Debt	127.0	127.0	0.0	127.0	126.2	126.2	0.0	126.2	253.2	253.2	0.0	253.2
3	ROE	216.4	216.4	0.0	216.4	214.6	214.6	0.0	214.6	431.0	431.0	0.0	431.0
4	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	**Total**	**347.1**	**347.1**	0.0	**347.1**	**345.4**	**345.4**	0.0	**345.4**	692.4	692.4	0.0	692.4
	Expenses ($M)												
6	OM&A	145.5	149.2	0.0	149.2	141.1	144.2	0.0	144.2	286.5	293.5	0.0	293.5
7	GRC	253.3	267.2	0.0	267.2	269.5	280.8	0.0	280.8	522.8	548.0	0.0	548.0
8	Depreciation/Amortization	82.1	82.1	0.0	82.1	81.9	81.9	0.0	81.9	164.0	164.0	0.0	164.0
9	Property Taxes	0.3	0.3	0.0	0.3	0.3	0.3	0.0	0.3	0.6	0.6	0.0	0.6
10	**Total**	**481.1**	**498.8**	0.0	**498.8**	**492.9**	**507.2**	0.0	**507.2**	**973.9**	**1,006.1**	0.0	**1,006.1**
	Other Revenues ($M)												
11	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Ancillary and Other Revenue	19.9	34.0	0.0	34.0	20.2	34.6	0.0	34.6	40.1	68.6	0.0	68.6
13	**Total**	**19.9**	**34.0**	0.0	**34.0**	**20.2**	**34.6**	0.0	**34.6**	**40.1**	**68.6**	0.0	**68.6**
14	**Regulatory Income Tax** ($M)	**48.5**	**48.0**	0.0	**48.0**	**61.5**	**61.8**	0.0	**61.8**	**110.0**	**109.8**	0.0	**109.8**
15	**Revenue Requirement** ($M)	**856.7**	**860.0**	0.0	**860.0**	**879.5**	**879.8**	0.0	**879.8**	**1,736.3**	**1,739.7**	0.0	**1,739.7**

Line No.	Description	Newly Regulated Hydroelectric Facilities											
		2014				2015				Total			
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Cost of Capital ($M)												
16	Short-term Debt	1.8	1.8	0.0	1.8	2.3	2.3	0.0	2.3	4.0	4.0	0.0	4.0
17	Long-Term Debt	62.2	62.2	0.0	62.2	62.7	62.7	0.0	62.7	125.0	125.0	0.0	125.0
18	ROE	106.0	106.0	0.0	106.0	106.7	106.7	0.0	106.7	212.7	212.7	0.0	212.7
19	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	**Total**	**170.0**	**170.0**	0.0	**170.0**	**171.7**	**171.7**	0.0	**171.7**	341.7	341.7	0.0	341.7
	Expenses ($M)												
21	OM&A	232.5	239.3	0.0	239.3	237.2	242.6	0.0	242.6	469.7	482.0	0.0	482.0
22	GRC	75.6	75.6	0.0	75.6	77.5	77.5	0.0	77.5	153.1	153.1	0.0	153.1
23	Depreciation/Amortization	62.2	62.2	0.0	62.2	63.1	63.1	0.0	63.1	125.3	125.3	0.0	125.3
24	Property Taxes	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.0	0.2
25	**Total**	**370.4**	**377.3**	0.0	**377.3**	**377.9**	**383.3**	0.0	**383.3**	**748.3**	**760.6**	0.0	**760.6**
	Other Revenues ($M)												
26	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	Ancillary and Other Revenue	22.7	22.7	0.0	22.7	23.1	23.1	0.0	23.1	45.8	45.8	0.0	45.8
28	**Total**	**22.7**	**22.7**	0.0	**22.7**	**23.1**	**23.1**	0.0	**23.1**	**45.8**	**45.8**	0.0	**45.8**
29	**Regulatory Income Tax** ($M)	**31.4**	**30.6**	0.0	**30.6**	**43.2**	**43.8**	0.0	**43.8**	**74.6**	**74.5**	0.0	**74.5**
30	**Revenue Requirement** ($M)	**549.1**	**555.2**	0.0	**555.2**	**569.7**	**575.8**	0.0	**575.8**	**1,118.8**	**1,131.0**	0.0	**1,131.0**

OPG Revenue Requirement

		Nuclear Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Cost of Capital ($M)												
31	Short-term Debt	1.6	1.6	0.0	1.6	2.1	2.1	0.0	2.1	3.7	3.7	0.0	3.7
32	Long-Term Debt	57.4	57.4	0.0	57.4	58.3	58.3	0.0	58.3	115.7	115.7	0.0	115.7
33	ROE	97.8	97.8	0.0	97.8	99.2	99.2	0.0	99.2	197.0	197.0	0.0	197.0
34	Adjustment for Lesser of UNL/ARC	74.6	74.6	0.0	74.6	70.3	70.3	0.0	70.3	144.9	144.9	0.0	144.9
35	**Total**	**231.4**	**231.4**	0.0	**231.4**	**229.9**	**229.9**	0.0	**229.9**	461.4	461.4	0.0	461.4
	Expenses ($M)												
36	OM&A	2,422.7	2,491.8	0.0	2,491.8	2,473.3	2,531.3	0.0	2,531.3	4,896.0	5,023.0	0.0	5,023.0
37	Fuel	280.5	268.6	0.0	268.6	267.9	260.5	0.0	260.5	548.4	529.0	0.0	529.0
38	Depreciation/Amortization	273.7	273.7	0.0	273.7	288.5	288.5	0.0	288.5	562.3	562.3	0.0	562.3
39	Property Taxes	15.9	15.9	0.0	15.9	16.4	16.4	0.0	16.4	32.4	32.4	0.0	32.4
40	**Total**	**2,992.8**	**3,050.0**	0.0	**3,050.0**	**3,046.3**	**3,096.7**	0.0	**3,096.7**	**6,039.1**	**6,146.7**	0.0	**6,146.7**
	Other Revenues ($M)												
41	Bruce Lease Net Revenues	39.7	39.7	0.0	39.7	40.6	40.6	0.0	40.6	80.3	80.3	0.0	80.3
42	Ancillary and Other Revenue	33.2	33.2	0.0	33.2	30.5	30.5	0.0	30.5	63.7	63.7	0.0	63.7
43	**Total**	**72.9**	**72.9**	0.0	**72.9**	**71.1**	**71.1**	0.0	**71.1**	**144.0**	**144.0**	0.0	**144.0**
44	**Regulatory Income Tax** ($M)	**140.8**	**132.8**	0.0	**132.8**	**47.5**	**51.9**	0.0	**51.9**	**188.3**	**184.7**	0.0	**184.7**
45	**Revenue Requirement** ($M)	**3,292.2**	**3,341.4**	0.0	**3,341.4**	**3,252.6**	**3,307.4**	0.0	**3,307.4**	**6,544.7**	**6,648.8**	0.0	**6,648.8**

		Total Generating Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Cost of Capital ($M)												
46	Short-term Debt	7.0	7.0	0.0	7.0	9.0	9.0	0.0	9.0	16.0	16.0	0.0	16.0
47	Long-Term Debt	246.6	246.6	0.0	246.6	247.3	247.3	0.0	247.3	493.9	493.9	0.0	493.9
48	ROE	420.2	420.2	0.0	420.2	420.5	420.5	0.0	420.5	840.7	840.7	0.0	840.7
49	Adjustment for Lesser of UNL/ARC	74.6	74.6	0.0	74.6	70.3	70.3	0.0	70.3	144.9	144.9	0.0	144.9
50	**Total**	**748.5**	**748.5**	0.0	**748.5**	**747.0**	**747.0**	0.0	**747.0**	1,495.5	1,495.5	0.0	1,495.5
	Expenses ($M)												
51	OM&A	2,800.6	2,880.3	0.0	2,880.3	2,851.6	2,918.1	0.0	2,918.1	5,652.2	5,798.4	0.0	5,798.4
52	Fuel and GRC	609.3	611.4	0.0	611.4	615.0	618.8	0.0	618.8	1,224.3	1,230.2	0.0	1,230.2
53	Depreciation/Amortization	418.0	418.0	0.0	418.0	433.6	433.6	0.0	433.6	851.6	851.6	0.0	851.6
54	Property Taxes	16.3	16.3	0.0	16.3	16.8	16.8	0.0	16.8	33.2	33.2	0.0	33.2
55	**Total**	**3,844.3**	**3,926.1**	0.0	**3,926.1**	**3,917.0**	**3,987.3**	0.0	**3,987.3**	**7,761.3**	**7,913.4**	0.0	**7,913.4**
	Other Revenues ($M)												
56	Bruce Lease Net Revenues	39.7	39.7	0.0	39.7	40.6	40.6	0.0	40.6	80.3	80.3	0.0	80.3
57	Ancillary and Other Revenue	75.7	89.8	0.0	89.8	73.8	88.2	0.0	88.2	149.5	178.0	0.0	178.0
58	**Total**	**115.4**	**129.5**	0.0	**129.5**	**114.4**	**128.8**	0.0	**128.8**	**229.8**	**258.3**	0.0	**258.3**
59	**Regulatory Income Tax** ($M)	**220.6**	**211.4**	0.0	**211.4**	**152.3**	**157.5**	0.0	**157.5**	**372.9**	**368.9**	0.0	**368.9**
60	**Revenue Requirement** ($M)	**4,698.0**	**4,756.5**	0.0	**4,756.5**	**4,701.8**	**4,763.0**	0.0	**4,763.0**	**9,399.8**	**9,519.5**	0.0	**9,519.5**

OPG Revenue Requirement Deficiency / (Sufficiency)

		Previously Regulated Hydroelectric Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Production & Revenue												
1	Forecast Production (TWh)	19.1	20.1	0.0	20.1	20.2	21.0	0.0	21.0	39.3	41.1	0.0	41.1
2	Current Payment Rate ($/MWh)	35.78	35.78	n/a	35.78	35.78	35.78	n/a	35.78	n/a	n/a	n/a	n/a
3	**Revenue From Current Payment Rate ($M)**	**681.9**	**718.6**	**0.0**	**718.6**	**723.6**	**752.4**	**0.0**	**752.4**	**1,405.5**	**1,471.1**	**0.0**	**1,471.1**
	Revenue Requirement												
4	Revenue Requirement ($M)	856.7	860.0	0.0	860.0	879.5	879.8	0.0	879.8	1,736.3	1,739.7	0.0	1,739.7
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**174.8**	**141.3**	0.0	**141.3**	**155.9**	**127.3**	0.0	**127.3**	**330.8**	**268.6**	0.0	**268.6**

		Nuclear Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Production & Revenue												
6	Forecast Production (TWh)	49.7	49.0	0.0	49.0	48.0	46.1	0.0	46.1	97.7	95.1	0.0	95.1
7	Current Payment Rate ($/MWh)	51.52	51.52	n/a	51.52	51.52	51.52	n/a	51.52	n/a	n/a	n/a	n/a
8	**Revenue From Current Payment Rate ($M)**	**2,560.5**	**2,526.8**	**0.0**	**2,526.8**	**2,473.0**	**2,373.4**	**0.0**	**2,373.4**	**5,033.5**	**4,900.2**	**0.0**	**4,900.2**
	Revenue Requirement												
9	Revenue Requirement ($M)	3,292.2	3,341.4	0.0	3,341.4	3,252.6	3,307.4	0.0	3,307.4	6,544.7	6,648.8	0.0	6,648.8
10	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**731.6**	**814.6**	0.0	**814.6**	**779.6**	**934.0**	0.0	**934.0**	**1,511.2**	**1,748.6**	0.0	**1,748.6**

		Total Previously Regulated Hydroelectric and Nuclear Generating Facilities											
		2014				2015				Total			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Production & Revenue												
12	Forecast Production (TWh)	68.8	69.1	0.0	69.1	68.2	67.1	0.0	67.1	137.0	136.2	0.0	136.2
12	Current Payment Rate ($/MWh)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	**Revenue From Current Payment Rate ($M)**	**3,242.4**	**3,245.4**	**0.0**	**3,245.4**	**3,196.6**	**3,125.8**	**0.0**	**3,125.8**	**6,439.0**	**6,371.2**	**0.0**	**6,371.2**
	Revenue Requirement												
14	Revenue Requirement ($M)	4,148.9	4,201.3	0.0	4,201.3	4,132.1	4,187.2	0.0	4,187.2	8,281.0	8,388.5	0.0	8,388.5
15	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**906.5**	**955.9**	0.0	**955.9**	**935.5**	**1,061.4**	0.0	**1,061.4**	**1,842.0**	**2,017.2**	0.0	**2,017.2**

OPG Requested Payment Amounts

		Previously Regulated Hydroelectric Facilities											
		2014				2015				2014-2015 Test Period			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Revenue Requirement ($M)	856.7	860.0	0.0	860.0	879.5	879.8	0.0	879.8	1,736.3	1,739.7	0.0	1,739.7
2	Forecast Production (TWh)	19.1	20.1	0.0	20.1	20.2	21.0	0.0	21.0	39.3	41.1	0.0	41.1
3	**Requested Payment Amount ($/MWh)** (line 1 / line 2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**44.20**	**42.31**	**-**	**42.31**

		Newly Regulated Hydroelectric Facilities											
		July 1, 2014 - December 31, 2014				2015				July 1, 2014 - 2015 Test Period			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
4	Revenue Requirement[1] ($M)	274.6	277.6	0.0	277.6	569.7	575.8	0.0	575.8	844.3	853.4	0.0	853.4
5	Forecast Production[2] (TWh)	5.5	5.5	0.0	5.5	12.5	12.5	0.0	12.5	17.9	17.9	0.0	17.9
6	**Requested Payment Amount ($/MWh)** (line 4 / line 5)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**47.08**	**47.59**	**-**	**47.59**

		Nuclear Facilities											
		2014				2015				2014-2015 Test Period			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
7	Revenue Requirement ($M)	3,292.2	3,341.4	0.0	3,341.4	3,252.6	3,307.4	0.0	3,307.4	6,544.7	6,648.8	0.0	6,648.8
8	Forecast Production (TWh)	49.7	49.0	0.0	49.0	48.0	46.1	0.0	46.1	97.7	95.1	0.0	95.1
9	**Requested Payment Amount ($/MWh)** (line 7 / line 8)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	**66.99**	**69.91**	**-**	**69.91**

		Total Generating Facilities											
		2014				2015				2014-2015 Test Period			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
10	Revenue Requirement ($M)	4,423.4	4,478.9	0.0	4,478.9	4,701.8	4,763.0	0.0	4,763.0	9,125.3	9,241.9	0.0	9,241.9
11	Forecast Production (TWh)	74.2	74.6	0.0	74.6	80.7	79.6	0.0	79.6	154.9	154.2	0.0	154.2
12	**Requested Payment Amount ($/MWh)**	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

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

OPG Recovery of Deferral and Variance Accounts and Riders

Line No.	Description	Previously Regulated Hydroelectric Facilities Amortization 2015 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
1	Capacity Refurbishment Variance	57.2	57.2	0.0	57.2
2	Hydroelectric Incentive Mechanism Variance	(2.4)	(2.4)	0.0	(2.4)
3	Surplus Baseload Generation Variance	8.1	8.1	0.0	8.1
4	**Total**	**62.9**	**62.9**	0.0	**62.9**
5	**Forecast Production** (TWh)	**20.2**	**21.0**	0.0	**21.0**
6	**Rider** ($/MWh) (line 4 / line 5)	**3.11**	**2.99**	-	**2.99**

Line No.	Description	Nuclear Facilities Amortization 2015 OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
7	Capacity Refurbishment Variance	3.7	3.7	0.0	3.7
8	Nuclear Development Variance	69.4	69.4	0.0	69.4
9	**Total**	**73.1**	**73.1**	0.0	**73.1**
10	**Forecast Production** (TWh)	**48.0**	**46.1**	0.0	**46.1**
11	**Rider** ($/MWh) (line 9 / line 10)	**1.52**	**1.59**	-	**1.59**

OPG 2014-2015 Test Period Consumer Impact

Line No.	Description	Residential Consumers EB-2010-0008 / EB-2012-0002 >> EB-2013-0321 Previously Regulated Hydroelectric & Nuclear Facilities OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Production and Demand				
1	Typical Usage, including Line Losses[1] (kWh/Month)	842.3	842.3	n/a	842.3
2	Forecast Production (TWh)	137.0	136.2	-	136.2
3	IESO Forecast Provincial Demand[2] (TWh)	282.4	282.4	n/a	282.4
4	OPG Proportion of Consumer Usage (line 2 / line 3)	48.51%	48.24%	0.00%	48.24%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	408.6	406.3	-	406.3
6	**Typical Bill[1] ($/Month)**	**118.69**	**118.69**	n/a	**118.69**
	Production-Weighted Average Rates				
7	EB-2010-0008 / EB-2012-0002 Production-Weighted Average Rate ($/MWh) (line 23)	52.35	52.06	-	52.06
8	EB-2013-0321 Production-Weighted Average Rate ($/MWh) (line 41)	63.24	64.38	-	64.38
	Impact				
9	**Typical Bill Impact[3]** ($/Month)	**4.45**	**5.00**	**-**	**5.00**
10	**Percentage Change of Typical Bill** (line 9 / line 6)	**3.7%**	**4.2%**	**0.0%**	**4.2%**

Line No.	Description	EB-2010-0008 / EB-2012-0002 Current Rates Previously Regulated Hydroelectric & Nuclear Facilities OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Payment Amounts ($MWh)				
11	Previously Regulated Hydroelectric	35.78	35.78	n/a	35.78
12	Nuclear	51.52	51.52	n/a	51.52
	Riders ($MWh)				
13	Previously Regulated Hydroelectric	3.04	3.04	n/a	3.04
14	Nuclear	6.27	6.27	n/a	6.27
	Total Annual Rates ($MWh)				
15	Previously Regulated Hydroelectric	38.82	38.82	n/a	38.82
16	Nuclear	57.79	57.79	n/a	57.79
	Forecast Production EB-2013-0321 (TWh)				
17	Previously Regulated Hydroelectric	39.3	41.1	-	41.1
18	Nuclear	97.7	95.1	-	95.1
19	**Total**	**137.0**	**136.2**	**-**	**136.2**
	Production-Weighted Average Rates ($MWh)				
20	Previously Regulated Hydroelectric	11.13	11.72	-	11.72
21	Nuclear	41.22	40.35	-	40.35
22	**Total** (line 20 + line 21)	**52.35**	**52.06**	**-**	**52.06**
23	**Total Production-Weighted Average Rate** ($MWh)	**52.35**	**52.06**	**-**	**52.06**

OPG 2014-2015 Test Period Consumer Impact

Line No.	Description	EB-2013-0321 Test Period Revenue Previously Regulated Hydroelectric & Nuclear Facilities OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	EB-2012-0002 2014 Approved Riders and Forecasted Revenue ($M)				
24	Previously Regulated Hydroelectric Rider	2.02	2.02	n/a	2.02
25	Previously Regulated Hydroelectric Rider Revenue	38.50	40.57	-	40.57
26	Nuclear Rider	4.18	4.18	n/a	4.18
27	Nuclear Rider Revenue	207.75	205.01	-	205.01
28	**Total Revenue**	**246.24**	**245.58**	**-**	**245.58**
	EB-2013-0321 2015 Proposed Riders and Forecasted Revenue ($M)				
29	Previously Regulated Hydroelectric Rider	3.11	2.99	-	2.99
30	Previously Regulated Hydroelectric Rider Revenue	62.88	62.88	-	62.88
31	Nuclear Rider	1.52	1.59	-	1.59
32	Nuclear Rider Revenue	73.07	73.07	-	73.07
33	**Total Revenue**	**135.95**	**135.95**	**-**	**135.95**
	EB-2013-0321 2014-2015 Test Period Revenue Requirement ($M)				
34	Previously Regulated Hydroelectric Revenue	1,736.3	1,739.7	-	1,739.7
35	Nuclear Revenue	6,544.7	6,648.8	-	6,648.8
36	**Total Revenue**	**8,281.0**	**8,388.5**	**-**	**8,388.5**
37	**Total Test Period Revenue** ($M) (line 28 + line 33 + line 36)	**8,663.2**	**8,770.0**	**-**	**8,770.0**
	Forecast Production EB-2013-0321 (TWh)				
38	Previously Regulated Hydroelectric	39.28	41.11	-	41.11
39	Nuclear	97.70	95.11	-	95.11
40	**Total**	**136.98**	**136.23**	**-**	**136.23**
41	**Total Production-Weighted Average Rate** ($/MWh) (line 37 / line 40)	**63.24**	**64.38**	**-**	**64.38**

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

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

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

Board Staff Interrogatory #002

Ref:

Issue Number: 1.0
Issue: General

Interrogatory

2013 Actual Results
Procedural Order No. 1 established March 19, 2014 as the date on which OPG will file interrogatory responses. To the extent that 2013 actual results are available, please update the evidence accordingly. Updated tables should consist of a new column "2013 Actual" beside "2013 Budget". The spreadsheets that were filed should be updated in the same manner.

As above, please provide updated deferral and variance account evidence in Exh H1-1-1 including the account balances and applicable tables to reflect 2013 actual amounts. In addition, please provide the proposed consequential changes (e.g., proposed payment riders).

Please reflect 2013 actual results in the responses to interrogatories where applicable.

Response

To respond to this request as written would require OPG to reproduce its entire application. Like all applications, OPG's filing employs a bridge year in advance of the test period. In this regard, for any proceeding an applicant could continually update as new actual information about the bridge year becomes available, but this is not done because the application is based on the revenue requirement forecast for the test period, not the bridge year. OPG's Application contains 2013 budget information, which was the best available at the time of filing.

Recognizing that all of the requested information cannot reasonably be assembled and submitted during the interrogatory period, in the attached tables OPG has provided 2013 actual information for the key tables in the Application. Also, where possible, OPG has included 2013 actual information in response to other interrogatory requests. In addition, the attachments to Ex. L-9.1-17 SEC-132 provide updated deferral and variance account balances. OPG has not undertaken variance analyses associated with 2013 actual values.

Numbers may not add due to rounding.

Table 1
Summary of Actual Results ($M)
Year Ending December 31, 2013

Line No.	Description	Note	Previously Regulated Hydroelectric 2013 Budget	Previously Regulated Hydroelectric (c)-(a) Change	Previously Regulated Hydroelectric 2013 Actual	Newly Regulated Hydroelectric[1] 2013 Budget	Newly Regulated Hydroelectric[1] (f)-(d) Change	Newly Regulated Hydroelectric[1] 2013 Actual	Nuclear 2013 Budget	Nuclear (i)-(g) Change	Nuclear 2013 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Rate Base										
1	**Net Fixed Assets**	2	4,809.1	(2.8)	4,806.3	2,507.0	11.4	2,518.4	2,992.8	11.0	3,003.8
2	**Working Capital**	3	0.7	(0.2)	0.5	0.7	(0.1)	0.6	731.3	12.8	744.1
3	**Cash Working Capital**	3	21.7	0.0	21.7	8.3	0.0	8.3	32.0	0.0	32.0
4	**Total Rate Base**		4,831.5	(3.0)	4,828.5	2,516.0	11.3	2,527.3	3,756.1	23.7	3,779.8
	Capitalization										
5	**Short-term Debt**	4	40.4	(32.6)	7.8	N/A	N/A	N/A	19.1	(15.4)	3.7
6	**Long-Term Debt**	4	2,520.3	31.0	2,551.3	N/A	N/A	N/A	1,192.4	28.0	1,220.4
7	**Common Equity**	4	2,270.8	(1.4)	2,269.4	N/A	N/A	N/A	1,074.4	11.2	1,085.5
8	**Adjustment for Lesser of UNL or ARC**	4	N/A	N/A	N/A	N/A	N/A	N/A	1,470.2	(0.0)	1,470.2
9	**Total Capital**		4,831.5	(3.0)	4,828.5	N/A	N/A	N/A	3,756.1	23.7	3,779.8
	Cost of Capital										
10	**Short-term Debt**	5	2.9	(1.4)	1.6	N/A	N/A	N/A	1.4	(0.6)	0.7
11	**Long-Term Debt**	5	127.9	2.7	130.6	N/A	N/A	N/A	60.5	2.0	62.5
12	**Return on Equity**	5	64.1	(79.0)	(14.9)	N/A	N/A	N/A	30.3	(37.5)	(7.1)
13	**Adjustment for Lesser of UNL or ARC**	5	N/A	N/A	N/A	N/A	N/A	N/A	78.9	(0.0)	78.9
14	**Total Cost of Capital**		194.9	(77.7)	117.2	N/A	N/A	N/A	171.2	(36.1)	135.0
	Expenses:										
15	**OM&A**	6	141.3	(16.6)	124.7	218.2	(21.6)	196.6	2,493.0	(89.4)	2,403.6
16	**Fuel and GRC**	7	243.5	6.0	249.5	75.6	(0.2)	75.4	272.6	(27.9)	244.7
17	**Depreciation & Amortization**	8	79.0	1.4	80.5	61.4	(2.4)	59.0	256.5	13.6	270.1
18	**Property Tax**	9	0.3	(0.1)	0.2	0.1	0.1	0.2	15.3	(1.3)	14.0
19	**Total Expenses**		464.2	(9.3)	454.8	355.4	(24.1)	331.3	3,037.4	(104.9)	2,932.5
	Less:										
	Other Revenues										
20	**Bruce Lease Revenues Net of Direct Costs**	10	N/A	N/A	N/A	N/A	N/A	N/A	42.3	(36.2)	6.1
21	**Ancillary and Other Revenue**	11	31.8	16.7	48.6	22.2	13.5	35.7	24.8	12.9	37.6
22	**Total Other Revenues**		31.8	16.7	48.6	22.2	13.5	35.7	67.1	(23.3)	43.7
23	**Income Tax**	12	(0.7)	0.6	(0.1)	N/A	N/A	N/A	(23.9)	(33.1)	(57.0)

Notes:

1. Although regulation of Newly Regulated Hydroelectric facilities is expected to begin on July 1, 2014, 2013 amounts are shown for comparison purposes where applicable.
2. 2013 Budget from Ex. B2-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. B1-1-1 Table 2 (Nuclear).
   2013 Actuals from Ex. L-01.0.1 Staff-002, Attachment 1, Table 2, col. (f) less Table 3, col. (e).
3. 2013 Budget from Ex. B2-5-1 Table 1 (Prev. Reg. Hydro), Ex. B2-5-1 Table 2 (Newly Reg. Hydro) and Ex. B3-5-1 Table 1 (Nuclear).
   2013 Actuals from Ex. L-01.0.1 Staff-002, Attachment 1, Table 4.
4. 2013 Budget totals from Ex. C1-1-1 Table 3 (col. (a)). 2013 Actual totals from Ex. L-01.0.1 Staff-002, Attachment 1, Table 5, (col. (a)).
   Capitalization is allocated to Previously Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
   Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Table 3 (2013 Budget) and Ex. L-01.0.1 Staff-002, Attachment 1, Table 5 (2013 Actual).
5. 2013 Budget totals from Exhibit C1-1-1 Table 3 (col. (d)). 2013 Actual totals from Ex. L-01.0.1 Staff-002, Attachment 1, Table 5,(col. (d)).
   Cost of Capital is allocated to Previously Regulated Hydroelectric and Nuclear operations using rate base financed by capital structure.
   Capital Structure for OPG's combined regulated operations is provided in Ex. C1-1-1 Table 3 (2013 Budget) and Ex. L-01.0.1 Staff-002, Attachment 1, Table 5 (2013 Actual).
6. 2013 Budget from Ex. F1-1-1 Table 1 (Prev. Reg. Hydro), Ex. F1-1-1 Table 2 (Newly Reg. Hydro) and Ex. F2-1-1 Table 1 (Nuclear).
   2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 15 (Prev. Reg. Hydro), Table 16 (Newly Reg. Hydro) and Table 19 (Nuclear).
7. 2013 Budget from Ex. F1-4-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. F2-5-1 Table 1 (Nuclear).
   2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 15 (Prev. Reg. Hydro), Table 16 (Newly Reg. Hydro) and Table 19 (Nuclear).
8. 2013 Budget from Ex. F4-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro); Ex. F4-1-1 Table 2 (Nuclear).
   2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 27 (Prev. Reg. Hydro and Newly Reg. Hydro) and Table 28 (Nuclear).
9. 2013 Budget from Ex. F4-2-1 Table 1 (Prev. Reg. Hydro), Ex. F4-2-1 Table 2 (Newly Reg. Hydro), Ex. F4-2-1 Table 3 (Nuclear).
   2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 15 (Prev. Reg. Hydro), Table 16 (Newly Reg. Hydro) and Table 19 (Nuclear).
10. 2013 Budget from Ex. G2-2-1 Table 1.
    2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 36.
11. 2013 Budget From Ex. G1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro), Ex. G2-1-1 Table 1 (Nuclear).
    2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 34 (Prev. Reg. Hydro and Newly Reg. Hydro) and Table 35 (Nuclear).
12. 2013 Budget from Ex. F4-2-1 Table 1 (Prev. Reg. Hydro) and Ex. F4-2-1 Table 3 (Nuclear).
    2013 Actual from Ex. L-01.0.1 Staff-002, Attachment 1, Table 15 (Prev. Reg. Hydro) and Table 19 (Nuclear).

Table 2
Continuity of Property, Plant and Equipment ($M)
Actual - Year Ending December 31, 2013

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	Hydroelectric:						
	Niagara Plant Group and Saunders GS:						
1	Niagara Plant Group	2,969.6	43.4	0.0	43.4	3,013.0	2,991.3
2	Niagara Tunnel Project[1]	19.2	1,439.2	0.0	1,439.2	1,458.4	1,148.4
3	Saunders GS	1,559.9	3.0	0.0	3.0	1,562.9	1,561.4
4	Sub total	4,548.7	1,485.6	0.0	1,485.6	6,034.3	5,701.1
	Newly Regulated Hydroelectric:[2]						
5	Ottawa-St. Lawrence Plant Group[3]	1,572.6	26.5	(6.1)	20.4	1,593.0	1,582.8
6	Central Hydro Plant Group	115.6	9.5	(0.4)	9.1	124.7	120.2
7	Northeast Plant Group	688.3	30.9	(2.1)	28.8	717.1	702.7
8	Northwest Plant Group	825.0	6.6	(0.4)	6.2	831.2	828.1
9	Sub total	3,201.5	73.5	(9.0)	64.5	3,266.0	3,233.8
10	Total Hydroelectric	7,750.2	1,559.1	(9.0)	1,550.1	9,300.3	8,934.9
	Nuclear:						
11	Darlington NGS[4,5]	764.6	182.5	1.2	183.7	948.4	863.2
12	Pickering NGS	1,959.6	99.7	(2.6)	97.1	2,056.7	2,008.1
13	Nuclear Support Divisions[6]	316.8	33.9	(3.2)	30.7	347.5	332.1
14	Nuclear - Excluding Asset Retirement Costs	3,041.0	316.1	(4.6)	311.5	3,352.5	3,203.5
15	Asset Retirement Costs	2,839.2	0.0	0.0	0.0	2,839.2	2,839.2
16	Total Nuclear	5,880.2	316.1	(4.6)	311.5	6,191.7	6,042.7

Notes:
1 In-service additions for 2013 as shown in Ex. L9.1-17 SEC-131 Chart 1 and consist of $1,424.9M placed in-service during March 2013 and $14.3M placed in-service at the end of November 2013. These amounts are assigned a weighting of 9.5/12 and 1/12, respectively, in calculating the 2013 Gross Plant Rate Base amount.
2 Newly Regulated Hydroelectric is not regulated in 2013. Amounts are presented for illustrative comparison and continuity purposes only.
3 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group (i.e. Saunders GS costs are excluded).
4 Reflects in-service addition of $80.7M for the Darlington Energy Complex placed in-service at the beginning of June 2013. This amount is assigned a seven-month weighting in calculating the 2013 Gross Plant Rate Base amount.
5 Col. (c) reflects an adjustment to reclassify the gross plant value of $5.0M for the Water and Sewer project (placed in-service in 2012) from Nuclear Support Divisions (line 13) to Darlington NGS (Line 11), as this is a Facility and Infrastructure project associated with Darlington Refurbishment. The Water and Sewer project is discussed in Ex. D2-2-1, section 7.2.2.
6 Includes support divisions within Nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

Table 3
Continuity of Accumulated Depreciation and Amortization ($M)
Actual - Year Ending December 31, 2013

Line No.	Prescribed Facility	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	Hydroelectric:					
	Niagara Plant Group and Saunders GS:					
1	**Niagara Plant Group**	563.8	45.6	0.2	609.6	586.7
2	**Niagara Tunnel Project**	1.5	13.0	0.0	14.5	8.0
3	**Saunders GS**	289.1	21.9	0.0	311.0	300.1
4	**Sub total**	854.4	80.5	0.2	935.2	894.8
	Newly Regulated Hydroelectric:[1]					
5	**Ottawa-St. Lawrence Plant Group**[2]	335.4	27.7	(3.9)	359.2	347.3
6	**Central Hydro Plant Group**	21.9	2.3	(0.2)	24.0	23.0
7	**Northeast Plant Group**	145.6	11.8	(0.5)	156.9	151.3
8	**Northwest Plant Group**	186.7	14.8	(0.5)	201.0	193.9
9	**Sub total**	689.6	56.6	(5.1)	741.1	715.4
10	**Total Hydroelectric:**	1,544.0	137.1	(4.9)	1,676.3	1,610.2
	Nuclear:					
11	**Darlington NGS**[3]	279.8	34.6	(2.2)	312.2	296.0
12	**Pickering NGS**	1,082.9	127.5	(1.7)	1,208.7	1,145.8
13	**Nuclear Support Divisions**[4]	214.2	27.3	0.4	241.9	228.1
14	**Nuclear - Excluding Asset Retirement Costs**	1,576.9	189.4	(3.5)	1,762.8	1,669.9
15	**Asset Retirement Costs**	1,328.6	80.7	0.0	1,409.4	1,369.0
16	**Total Nuclear:**	2,905.6	270.1	(3.5)	3,172.2	3,038.9

Notes:
1 Newly Regulated Hydroelectric is not regulated in 2013. Amounts are presented for illustrative comparison and continuity purposes only.
2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group (i.e. Saunders GS costs are excluded).
3 Col. (c) reflects an adjustment to reclassify accumulated depreciation of $0.2M for the Water and Sewer project (placed in-service in 2012) from Nuclear Support Divisions (line 13) to Darlington NGS (Line 11), as this is a Facility and Infrastructure project associated with Darlington Refurbishment. The Water and Sewer project is discussed in Ex. D2-2-1, section 7.2.2.
4 Includes support divisions within Nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

Numbers may not add due to rounding.

Table 4
Working Capital Summary ($M)
Actual - Year Ending December 31, 2013

Line No.	Working Capital Item	Opening Balance	Closing Balance	(a+b)/2 Rate Base Value
		(a)	(b)	(c)
	Previously Regulated Hydroelectric:			
1	**Cash Working Capital[1]**	N/A	N/A	21.7
2	**Materials & Supplies**	0.7	0.3	0.5
3	**Total**			22.2
	Newly Regulated Hydroelectric:[2]			
4	**Cash Working Capital[1]**	N/A	N/A	8.3
5	**Materials & Supplies**	0.7	0.5	0.6
6	**Total**			8.9
	Nuclear			
7	**Cash Working Capital[1]**	N/A	N/A	32.0
8	**Fuel Inventory**	327.4	333.8	330.6
9	**Materials & Supplies**	410.5	416.4	413.5
10	**Total**			776.1

Notes:

1 As 2013 actual cash working capital amounts have not been finalized at the time of filing of this interrogatory response, 2013 budget values are provided, as per Ex. B2-5-1 Table 1 (Previously Regulated Hydroelectric), Ex. B2-5-1 Table 2 (Newly Regulated Hydroelectric), and Ex. B3-5-1 Table 1 (Nuclear).

2 Newly Regulated Hydroelectric is not regulated in 2013. Amounts are presented for illustrative comparison and continuity purposes only.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	11.5	0.2%	1.17%	2.3
2	**Existing/Planned Long-Term Debt**	2	2,336.7	32.7%	5.12%	119.6
3	**Other Long-Term Debt Provision**	3	1,435.0	20.1%	5.12%	73.4
4	**Total Debt**	4	3,783.2	53.0%	5.16%	195.3
5	**Common Equity**	4	3,354.9	47.0%	-0.66%	(22.1)
6	**Rate Base Financed by Capital Structure**	5	7,138.2	82.9%	2.43%	173.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,470.2	17.1%	5.37%	78.9
8	**Rate Base**	7	8,608.3	100%	2.93%	252.2

Notes:

1 Principal of $11.5M at a debt rate of 1.17% is associated with borrowing under commercial paper program. There was no borrowing under the A/R Securitization program. Cost is $2.3M. Reflecting regulated portion of facility cost of $2.6M in 2013. Principal and cost amounts are the portion allocated to regulated operations using the 86.5% ratio provided in Ex. C1-1-3 Table 1, line 14. An updated 2013 allocation ratio had not been developed at the time of filing interrogatories.

2 Principal from Ex. L-01.0.1 Staff-002, Attachment 1, Table 6, line 40.

3 Debt required to balance capital structure with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure approved by the OEB in EB-2010-0008 as discussed in Ex. C1-1-1. The Return on Equity is determined as Regulatory EBT from Ex. L-01.0.1 Staff-002, Attachment 1, Table 29, line 1, less regulatory tax determined at Ex. L-01.0.1 Staff-002, Attachment 1, Table 29, line 25, less income tax variances recorded in deferral and variance accounts for 2013 of ($4.5M).

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. L-01.0.1 Staff-002, Attachment 1, Table 7, line 33. Weighted average accretion rate from Ex. C1-1-1 Table 3.

7 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 1, line 4, col. (c) (Prev. Reg. Hydro) and Table 1, col (i) (Nuclear). Newly regulated hydroelectric assets are not included in the Board Approved capitalization and Cost of Capital.

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2013

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008							
	Issues 5 and 6 Redeemed During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Redeemed During 2010							
	Issues 9 and 10 Redeemed During 2011							
	Issue 16 Redeemed During 2012						**(Note 4)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 22**		300.0	3/22/2010	5.0	3/22/2015	3.56%	10.7
7	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
8	**Issue 24**		200.0	9/22/2010	5.0	9/22/2015	3.24%	6.5
9	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
10	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
11	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
12	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
13	**Total**	6	**2,460.0**				**4.72%**	**116.0**
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	3	**1,279.0**				**4.72%**	**60.3**
	Project Financing - Regulated Projects							
15	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**	1,5	18.8	1/22/2013	10.0	1/22/2023	5.35%	1.0
38	**Niagara 24**	2,5	13.9	4/22/2013	10.0	4/22/2023	5.37%	0.7
39	**Total**	6	**1,057.7**				**5.60%**	**59.3**
	Total Regulated Funded Long-Term Debt							
40	Line 14+39		**2,336.7**				**5.12%**	**119.6**

See Ex. L-01.0.1 Staff-002, Attachment 1, Table 6a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 6a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2013
Notes to Ex. L-01.0.1 Staff-002, Attachment 1, Table 6

	Issue	Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Niagara 23	1/22/2013	20.0	343.0	18.8
Note 2	Niagara 24	4/22/2013	20.0	253.0	13.9

Note 3 Allocation ratio for 2013 described in Ex. C1-1-2 Table 1, line 17 (excludes Newly Regulated Hydroelectric net fixed assets). The 2012 allocation ratio is used as it reflects OPG's most recent available financing results, as an updated 2013 allocation ratio had not been developed at the time of filing interrogatories.

Note 4 Includes related costs of issuance/redemption and the amortization of debt discount or premium.

Note 5 Realized effective rate on 2013 debt

New Issues	Effective Rate
Niagara 23	5.35%
Niagara 24	5.37%
Average Rate	5.36%

Note 6 Issue 29, Niagara 25 and Niagara 26 were not issued due to lower than expected financing requirement during Q3-Q4 2013

Table 7
Nuclear Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Year Ending December 31, 2013

Line No.	Description	Note	2013 Actual Prescribed Facilities	2013 Actual Bruce Facilities
			(a)	(b)
	ASSET RETIREMENT OBLIGATION			
1	**Opening Balance**	1	8,034.1	7,125.5
2	**Darlington Refurbishment Adjustment**		0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		8,034.1	7,125.5
4	**Used Fuel Storage and Disposal Variable Expenses**		49.0	54.0
5	**Low & Intermediate Level Waste Management Variable Expenses**		3.3	2.8
6	**Accretion Expense**		442.7	369.0
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(104.7)	(90.0)
8	**Consolidation and Other Adjustments**		(0.1)	(0.1)
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		8,424.3	7,461.2
10	**Current Approved ONFA Reference Plan Adjustment**		0.0	0.0
11	**New CNSC Requirements Adjustment**		0.0	0.0
12	**Closing Balance** (line 9 + line 10 + line 11)		8,424.3	7,461.2
13	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		8,229.2	7,293.3
	NUCLEAR SEGREGATED FUNDS BALANCE			
14	**Opening Balance**	1	6,316.5	6,400.1
15	**Earnings (Losses)**		332.9	337.1
16	**Contributions**		98.1	85.9
17	**Disbursements**		(44.7)	(30.4)
18	**Closing Balance** (line 14 + line 15 + line 16 + line 17)		6,702.8	6,792.7
19	**Average Nuclear Segregated Funds Balance** ((line 14 + line 18)/2)		6,509.6	6,596.4
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)			
20	**Opening Balance** (line 3 - line 14)		1,717.6	
21	**Closing Balance** (line 9 - line 18)		1,721.5	
22	**Average Unfunded Nuclear Liability Balance** ((line 20 + line 21)/2)		1,719.6	
	ASSET RETIREMENT COSTS (ARC)			
23	**Opening Balance**	1	1,510.5	1,944.8
24	**Reconciliation Adjustment**		0.0	0.0
25	**Darlington Refurbishment Adjustment**		0.0	0.0
26	**Adjusted Opening Balance** (line 23 + line 24 + line 25)		1,510.5	1,944.8
27	**Depreciation Expense**		(80.7)	(101.2)
28	**Closing Balance Before Year-End Adjustments** (line 26 + line 27)		1,429.8	1,843.6
29	**Current Approved ONFA Reference Plan Adjustment**		0.0	0.0
30	**New CNSC Requirements Adjustment**		0.0	0.0
31	**Closing Balance** (line 28 + line 29 + line 30)		1,429.8	1,843.6
32	**Average Asset Retirement Costs** ((line 26 + line 28)/2)		1,470.2	1,894.2
33	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 22 or line 32)		1,470.2	

Notes:
1 Opening balance for Prescribed Facilities from Ex. C2-1-1 Table 2, and Ex. C2-1-1 Table 3 for Bruce Facilities.

Numbers may not add due to rounding.

Table 8

Capital Expenditures Summary - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	28.5	27.2	27.1	20.9	24.8	34.3
2	**Saunders GS**	11.8	8.1	2.7	5.8	9.7	3.9
3	**Subtotal**	40.4	35.3	29.8	26.7	34.5	38.2
4	**Niagara Tunnel Project**	231.8	265.5	231.2	86.6	2.0	0.0
	Newly Regulated Hydroelectric:						
5	**Ottawa-St.Lawrence Plant Group**[1]	48.4	27.1	41.0	28.6	32.2	39.0
6	**Central Hydro Plant Group**	4.8	10.1	8.8	4.8	26.1	33.2
7	**Northeast Plant Group**	6.4	10.1	21.6	12.8	20.4	19.5
8	**Northwest Plant Group**	9.0	14.1	8.7	14.3	12.2	8.3
9	**Subtotal**	68.6	61.4	80.1	60.5	91.0	100.0
10	**Total**	340.7	362.2	341.0	173.9	127.5	138.2

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 9
Capital Expenditures Summary - Nuclear ($M)

Line No.	Category	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Operations Capital**	178.3	148.2	161.4	201.2	196.3	143.9
2	**Darlington Refurbishment Capital**	32.6	91.0	232.5	430.3	837.4	631.8
3	**Total Nuclear Capital**	210.9	239.2	393.8	631.5	1,033.7	775.7

Numbers may not add due to rounding.

Table 10

Capital Expenditures Summary - Nuclear Operations ($M)

Line No.	Category	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Portfolio Projects (Allocated)						
1	**Darlington NGS**	33.8	47.9	50.5	76.4	20.6	9.5
2	**Pickering NGS**	93.0	56.1	78.7	90.6	22.2	2.2
3	**Nuclear Support Divisions**	30.1	31.2	16.7	24.0	4.2	1.3
4	**Subtotal Portfolio Projects (Allocated)**	157.0	135.3	145.9	191.0	47.0	13.0
5	**Facility Projects to be Released**	0.0	0.0	0.0	0.0	0.0	0.0
6	**Portfolio Projects (Unallocated)**	0.0	0.0	0.0	0.0	128.0	109.2
7	**Subtotal Project Capital (Portfolio)**	157.0	135.3	145.9	191.0	175.0	122.2
8	**P2/P3 Isolation Project**	5.9	0.0	0.0	0.0	0.0	0.0
9	**Minor Fixed Assets**	15.4	12.9	15.5	10.2	21.3	21.7
10	**Total Nuclear Operations Capital**	178.3	148.2	161.4	201.2	196.3	143.9

Numbers may not add due to rounding.

Table 11

Capital Expenditures Summary - Nuclear Generation Development Projects ($M)

Line No.	Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Darlington Refurbishment						
1	**Darlington Refurbishment Project - Definition Phase**	25.7	63.3	153.0	329.7	664.0	572.3
	Facilities and Infrastructure - Released Projects:						
2	For In-Service at First Unit Refurburbishment	5.4	2.4	1.4	0.3	63.8	18.4
3	For In-Service at Project Completion	1.5	25.3	78.0	100.3	102.5	21.4
4	**Subtotal Released Projects**	6.9	27.6	79.4	100.6	166.2	39.8
5	**Facilities and Infrastrucure - Listed Work to be Released**	0.0	0.0	0.0	0.0	7.2	19.7
6	**Total Facilities and Infrastructure**	6.9	27.6	79.4	100.6	173.4	59.5
7	**Total Darlington Refurbishment**	32.6	91.0	232.5	430.3	837.4	631.8
8	**Darlington New Nuclear Project**	0.0	0.0	0.0	0.0	0.0	0.0
9	**Total Generation Development Capital**	32.6	91.0	232.5	430.3	837.4	631.8

Numbers may not add due to rounding.

Table 12
Capital Expenditures Summary - Corporate Groups ($M)
(Capital Expenditures in Corporate Groups Impacting Rate Base or the Asset Service Fee[1])

Line No.	Corporate Group	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**IT**	22.3	22.3	17.6	22.3	38.9	25.7
2	**Real Estate**	4.7	8.9	6.2	8.0	5.0	5.0
3	**Total**	27.0	31.2	23.8	30.3	43.9	30.7

Notes:
1 All amounts include those for newly regulated assets.

Numbers may not add due to rounding.

Table 13

Production Trend - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric (TWh)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	12.4	12.6	11.9	12.4	12.7	13.5
2	**Saunders GS**[1]	6.5	6.9	6.5	6.5	6.3	6.7
3	**Sub total**	18.9	19.5	18.5	18.9	19.1	20.2
	Newly Regulated Hydroelectric:						
4	**Ottawa-St. Lawrence Plant Group**[2]	4.7	5.7	5.1	6.3	5.7	5.7
5	**Central Hydro Plant Group**	0.5	0.5	0.4	0.5	0.4	0.5
6	**Northeast Plant Group**	1.4	2.0	2.0	2.3	2.5	2.5
7	**Northwest Plant Group**	3.4	3.3	3.3	3.4	3.8	3.8
8	**Sub total**	10.0	11.5	10.9	12.5	12.4	12.5
9	**Total**	28.9	31.0	29.4	31.3	31.4	32.7

Notes:

1 Saunders values represent total station production (including energy delivered to HQ).

2 Ottawa-St. Lawrence PG values are for the balance of the Plant Group, i.e. Saunders GS production is excluded.

Numbers may not add due to rounding.

Table 14
Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington NGS**	26.5	29.0	28.3	25.1	28.4	26.1
2	**Pickering NGS**	19.2	19.7	20.7	19.6	21.3	21.9
3	**Total**	45.8	48.6	49.0	44.7	49.7	48.0

Table 15

Operating Costs Summary - Previously Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A**[1]	59.4	50.1	60.2	61.6	74.6	68.6
2	**Project OM&A**	5.4	6.6	13.6	14.7	13.5	17.9
3	**Allocation of Corporate Costs**	22.4	22.0	24.5	26.1	29.8	26.9
4	**Allocation of Centrally Held Costs**	19.6	15.9	19.6	20.7	26.1	26.0
5	**Asset Service Fee**	2.1	1.6	1.8	1.6	1.5	1.7
6	**Total OM&A**	108.8	96.3	119.7	124.7	145.5	141.1
7	**Gross Revenue Charge**	252.2	259.4	244.5	249.5	253.3	269.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization**[2]	63.5	65.6	70.0	80.5	82.1	81.9
9	**Income Tax**	29.9	33.4	32.3	(0.1)	48.5	61.5
10	**Capital Tax**	2.8	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.1	0.2	0.2	0.2	0.3	0.3
12	**Total Operating Costs**	457.4	454.9	466.6	454.7	529.5	554.4

Notes:

1 2011 Actual Base OM&A cost includes an extraordinary credit of $19.0M in Niagara Plant Group related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

2 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 27, line 5.

Numbers may not add due to rounding.

Table 16

Operating Costs Summary - Newly Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A**	100.0	106.0	102.9	103.5	113.4	113.7
2	**Project OM&A**	39.8	21.6	20.3	23.1	24.5	32.1
3	**Allocation of Corporate Costs**	31.4	32.3	36.6	35.2	42.1	39.6
4	**Allocation of Centrally Held Costs**	19.0	25.1	33.1	31.8	49.6	48.7
5	**Asset Service Fee**	3.6	3.4	3.3	3.0	2.9	3.0
6	**Total OM&A**	193.8	188.4	196.2	196.6	232.5	237.2
7	**Gross Revenue Charge**	54.9	67.7	65.6	75.4	75.6	77.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization**[1]	58.3	58.0	58.6	59.0	62.2	63.1
9	**Income Tax**	N/A	N/A	N/A	N/A	31.4	43.2
10	**Capital Tax**	N/A	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.2	0.2	0.2	0.2	0.2	0.2
12	**Total Operating Costs**	307.2	314.3	320.6	331.3	401.9	421.2

Notes:

1 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 27, line 11.

Numbers may not add due to rounding.

Table 17

Base OM&A - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Base OM&A:						
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**[1]	44.3	33.7	45.4	46.1	56.8	50.4
2	**Saunders GS**	15.1	16.4	14.8	15.5	17.8	18.1
3	**Subtotal**	59.4	50.1	60.2	61.6	74.6	68.6
	Newly Regulated Hydroelectric:						
4	**Ottawa-St.Lawrence Plant Group**[2]	30.2	34.4	32.8	35.5	37.8	37.6
5	**Central Hydro Plant Group**	18.9	22.4	21.1	20.8	24.2	24.7
6	**Northeast Plant Group**	19.0	21.3	21.9	23.3	23.8	23.6
7	**Northwest Plant Group**	31.8	27.9	27.2	24.0	27.5	27.8
8	**Subtotal**	100.0	106.0	102.9	103.5	113.4	113.7
9	**Total Base OM&A**	159.4	156.1	163.1	165.2	188.0	182.3
	OM&A Labour:[3]						
	Niagara Plant Group and Saunders GS:						
10	**Niagara Plant Group**	27.6	30.7	31.7	32.1	36.1	35.5
11	**Saunders GS**	8.7	9.3	9.6	9.8	10.8	11.0
12	**Subtotal**	36.3	40.0	41.3	41.9	46.9	46.5
	Newly Regulated Hydroelectric:						
13	**Ottawa-St.Lawrence Plant Group**[2]	17.2	19.3	20.3	22.6	24.9	24.3
14	**Central Hydro Plant Group**	11.9	13.0	13.7	14.2	16.5	16.7
15	**Northeast Plant Group**	11.8	13.3	14.2	15.5	16.8	16.2
16	**Northwest Plant Group**	12.2	14.3	15.7	15.5	18.8	18.6
17	**Subtotal**	53.0	60.0	63.9	67.9	76.9	75.9
18	**Total OM&A Labour**	89.3	100.0	105.1	109.8	123.8	122.4

Notes:

1 Niagara Plant Group 2011 Actual costs include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

3 Labour expense is included in Base OM&A.

Numbers may not add due to rounding.

Table 18

Project OM&A - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	4.9	6.2	12.4	10.2	9.3	11.0
2	**Saunders GS**	0.4	0.4	1.2	4.5	4.2	7.0
3	**Subtotal**	5.4	6.6	13.6	14.7	13.5	17.9
	Newly Regulated Hydroelectric:						
4	**Ottawa-St.Lawrence Plant Group**[1]	10.6	8.5	12.0	9.2	9.0	19.0
5	**Central Hydro Plant Group**	3.1	4.1	1.2	2.6	4.2	4.0
6	**Northeast Plant Group**	10.9	2.6	1.9	4.3	7.8	6.0
7	**Northwest Plant Group**	15.2	6.5	5.3	6.9	3.5	3.2
8	**Subtotal**	39.8	21.6	20.3	23.1	24.5	32.1
9	**Total**	45.1	28.2	33.9	37.7	38.0	50.1

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 19
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
	Nuclear Operations OM&A						
1	**Base OM&A[1]**	1,181.4	1,249.1	1,102.6	1,127.7	1,151.1	1,154.0
2	**Project OM&A**	142.7	111.6	111.5	105.7	113.9	106.4
3	**Outage OM&A**	278.2	215.0	214.3	277.5	262.7	330.7
4	**Subtotal Nuclear Operations OM&A**	1,602.3	1,575.7	1,428.4	1,510.8	1,527.6	1,591.1
5	**Darlington Refurbishment OM&A**	3.2	2.6	2.8	6.3	19.6	18.2
6	**Darlington New Nuclear OM&A**	23.2	15.7	24.7	25.6	0.0	0.0
7	**Allocation of Corporate Costs**	226.5	233.1	408.4	428.3	433.9	417.4
8	**Allocation of Centrally Held Costs**	161.6	267.1	342.7	409.9	418.2	419.8
9	**Asset Service Fee**	24.5	22.1	23.0	22.7	23.3	26.8
10	**Subtotal Other OM&A**	438.9	540.6	801.6	892.8	895.0	882.2
11	**Total OM&A**	2,041.2	2,116.3	2,230.0	2,403.6	2,422.7	2,473.3
12	**Nuclear Fuel Costs**	197.8	228.9	265.1	244.7	280.5	267.9
	Other Operating Cost Items:						
13	**Depreciation and Amortization[2,3]**	231.1	228.6	341.9	270.1	273.7	288.5
14	**Income Tax**	0.0	(25.3)	9.4	(57.0)	140.8	47.5
15	**Capital Tax**	2.9	N/A	N/A	N/A	N/A	N/A
16	**Property Tax**	14.0	13.6	13.3	14.0	15.9	16.4
17	**Total Operating Costs**	2,487.0	2,562.1	2,859.6	2,875.4	3,133.6	3,093.8

Notes:
1 Includes nuclear waste management variable expenses for 2011 to 2015.
2 Includes nuclear waste management variable expenses for 2010.
3 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 28, line 7.

Table 20
Base OM&A - Nuclear ($M)

Line No.	Function	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Stations						
1	Darlington NGS	288.3	308.6	287.4	277.8	289.5	298.8
2	Pickering NGS	479.3	501.8	418.2	402.3	428.3	437.1
3	Pickering Continued Operations	4.8	17.2	14.6	9.9	11.2	0.0
4	**Total Stations**	772.4	827.7	720.1	690.0	729.0	735.9
	Support[1,2]						
5	Engineering	53.7	58.2	140.1	148.8	152.2	149.7
6	Projects & Modifications	8.2	7.8	14.1	7.4	5.4	5.8
7	Facilities Management	40.1	41.3				
8	Records and Admin	23.7	23.7				
9	Nuclear Programs & Training	117.4	118.5				
10	Nuclear Services			67.2	75.0	73.9	73.7
11	Fleet Operations and Maintenance			8.3	30.5	27.6	26.1
12	Security and Emergency Services[3]	58.2	57.0	66.1	79.9	85.0	83.6
13	Supply Chain	65.7	70.6				
14	Inspection & Maintenance Services	29.6	28.6	36.1	35.4	35.7	35.3
15	Other Support[4,5]	12.6	15.6	50.6	60.7	42.3	43.9
16	**Total Support**	409.1	421.4	382.5	437.7	422.1	418.1
17	**Total Base OM&A**	1,181.4	1,249.1	1,102.6	1,127.7	1,151.1	1,154.0

Notes:

1 Nuclear Support divisions includes base OM&A expenditures on Pickering Continued Operations as follows:

Table to Note 1 ($M)

Line No.	Function	2011 Actual	2012 Actual	2013 Actual	2014 Plan
		(a)	(b)	(c)	(d)
1a	Engineering	0.1	1.8	0.8	0.4
2a	Projects & Modifications	0.2	0.2	0.1	0.0
3a	Inspection & Maintenance Services	0.0	1.7	0.7	1.0
4a	Nuclear Services	0.0	0.3	0.0	0.0
5a	Total	0.3	4.0	1.6	1.4

2 Organizational changes occurring in 2012 as reflected in the table are discussed in Ex. F2-2-1.

3 Security and Emergency Services was "Security" prior to 2012.

4 Includes low and intermediate level waste management variable expenses starting in 2011, as follows: $0.9M in 2011, $5.1M in 2012, $3.3M in 2013, $3.1M in 2014 and $5.5M in 2015. In 2010 these expenses were classified as an element of depreciation and amortization expense and are presented in Ex. F4-1-1 Table 2. Waste management variable expenses are discussed in Ex. C2-1-1.

5 2010 Actual for Other Support includes $0.186M for Pickering B Refurbishment.

Numbers may not add due to rounding.

Table 21
Project OM&A Summary - Nuclear ($M)

Line No.	Category	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Portfolio Projects (Allocated)						
1	**Darlington NGS**	39.6	16.7	6.7	12.9	2.4	10.6
2	**Pickering NGS**	33.0	13.0	37.4	19.3	9.9	5.4
3	**Nuclear Support Divisions**	20.0	20.6	20.8	55.1	8.4	4.8
4	**Subtotal Portfolio Projects (Allocated)**	92.6	50.3	64.9	87.4	20.8	20.8
5	**Facility Projects to be Released**	0.0	0.0	0.0	0.0	0.0	0.0
6	**Infrastructure**	32.2	50.2	31.9	0.0	28.2	29.7
7	**Portfolio Projects (Unallocated)**	0.0	0.0	0.0	0.0	52.1	55.2
8	**Subtotal Project OM&A (Portfolio)**	124.8	100.5	96.8	87.4	101.1	105.8
9	**P2/P3 Isolation Project**	10.5	0.0	0.0	0.0	0.0	0.0
10	**Pickering Continued Operations**	1.7	1.0	3.5	9.2	6.0	0.0
11	**Fuel Channel Life Cycle Mgmt Project**	5.7	10.1	11.3	9.2	6.8	0.6
12	**Total Project OM&A**	142.7	111.6	111.5	105.7	113.9	106.4

Table 22
Outage OM&A - Nuclear ($M)

Line No.	Division	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
1	Darlington NGS	109.3	59.9	43.7	95.7	65.9	126.2
2	Pickering NGS	159.8	128.6	87.9	77.6	100.1	94.3
3	Pickering Continued Operations[1]	3.0	22.3	16.2	10.2	6.2	0.0
4	**Total Stations**	272.1	210.8	147.8	183.5	172.3	220.5
5	**Nuclear Support Divisions**[1,2]	6.1	4.3	66.5	94.0	90.4	110.3
6	**Total Outage OM&A**	278.2	215.0	214.3	277.5	262.7	330.7

Notes:

1 Nuclear Support Divisions includes Outage OM&A expenditures on Pickering Continued Operations as follows:

Table to Note 1 ($M)

Line No.	Division	2011 Actual	2012 Actual	2013 Actual	2014 Plan
		(a)	(b)	(c)	(d)
1a	Projects & Modifications	0.1	0.1	0.0	0.0
2a	Inspection & Maintenance Services	0.0	7.2	10.5	12.3
3a	Nuclear Services	0.0	0.3	0.0	0.0
4a	Total	0.1	7.6	10.5	12.3

2 Includes IMS Division starting in 2012, which was previously included under Darlington NGS and Pickering NGS.

Numbers may not add due to rounding.

Table 23
OM&A - Darlington Refurbishment ($M)

Line No.	Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington Refurbishment - Planning & Preparation**	2.8	2.1	2.1	4.6	13.7	9.0
2	**Facilities and Infrastructure Plan**	0.4	0.5	0.8	1.7	5.9	9.3
3	**Total Darlington Refurbishment OM&A**	3.2	2.6	2.8	6.3	19.6	18.2

Numbers may not add due to rounding.

Table 24

Corporate Support & Administrative Groups - OPG ($M)

Line No.	Corporate Costs	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Business and Administrative Service**	188.7	181.0	289.0	295.6	295.6	281.2
2	**Finance**	56.4	60.7	65.1	63.9	62.0	58.7
3	**People and Culture**	50.6	54.9	113.4	115.1	118.4	113.8
4	**Commercial Operations and Env.**	47.1	45.8	36.6	37.4	42.6	39.1
5	**Corporate Centre**	19.2	22.3	43.6	50.8	59.0	54.9
6	**Total**	362.0	364.7	547.7	562.8	577.6	547.8

Numbers may not add due to rounding.

Table 25

Allocation of Corporate Support & Administrative Costs - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Corporate Group	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Business and Administrative Service**	8.2	7.2	8.3	8.5	8.6	7.7
2	**Finance**	3.3	3.8	3.2	3.1	3.4	2.9
3	**People and Culture**	2.0	2.6	3.4	4.4	4.7	5.0
4	**Commercial Operations and Env.**	7.3	7.1	5.5	5.8	8.0	6.9
5	**Corporate Centre**	1.6	1.3	4.2	4.3	5.1	4.4
6	**Subtotal**	22.4	22.0	24.5	26.1	29.8	26.9
	Newly Regulated Hydroelectric:						
	Ottawa-St. Lawrence[1], Central, Northeast and Northwest Plant Groups:						
7	**Business and Administrative Service**	14.6	14.1	14.3	14.3	15.3	13.9
8	**Finance**	5.2	4.9	4.6	3.9	4.9	4.7
9	**People and Culture**	3.8	3.8	6.8	6.3	7.9	7.6
10	**Commercial Operations and Env.**	6.2	6.2	4.9	4.9	5.2	5.1
11	**Corporate Centre**	1.6	3.3	6.0	5.8	8.8	8.4
12	**Subtotal**	31.4	32.3	36.6	35.2	42.1	39.6
13	**Total**	53.8	54.3	61.1	61.3	71.9	66.5

Notes:

1 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 26

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

Line No.	Corporate Group	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Business and Administrative Service**	132.2	128.2	237.2	246.5	245.5	237.3
2	**Finance**	33.3	38.0	46.2	46.3	45.3	43.4
3	**People and Culture**	33.9	38.0	90.0	91.6	92.2	89.3
4	**Commercial Operations and Env.**	16.7	16.4	12.7	14.7	18.1	17.3
5	**Corporate Centre**	10.4	12.5	22.3	29.2	32.8	30.1
6	**Total**	226.5	233.1	408.4	428.3	433.9	417.4

Table 27

Depreciation and Amortization - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Niagara Plant Group**	41.9	42.7	44.0	45.6	44.3	44.3
2	**Niagara Tunnel Project**	0.3	0.3	0.3	13.0	15.8	15.8
3	**Saunders GS**	21.2	21.6	21.9	21.9	21.8	21.7
4	**Other**[1]	0.1	1.0	3.8	(0.0)	0.1	0.1
5	**Subtotal**	63.5	65.6	70.0	80.5	82.1	81.9
	Newly Regulated Hydroelectric:						
6	**Ottawa-St.Lawrence Plant Group**[2]	25.3	26.2	27.0	27.7	27.1	27.4
7	**Central Hydro Plant Group**	1.9	1.9	2.1	2.3	2.2	2.4
8	**Northeast Plant Group**	11.4	11.5	11.4	11.8	11.7	11.8
9	**Northwest Plant Group**	13.7	14.4	14.6	14.8	14.6	14.6
10	**Other**[1]	6.0	4.0	3.5	2.4	6.6	6.9
11	**Subtotal**	58.3	58.0	58.6	59.0	62.2	63.1
12	**Total**	121.8	123.5	128.6	139.5	144.3	145.0

Notes:

1 Includes losses on retirements, gains on sales and other related charges. Also includes asset removal costs for 2010 Actual. Starting with 2011 Actual, asset removal costs are included in hydroelectric OM&A, as discussed in Ex. F4-1-1.

2 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 28
Depreciation and Amortization - Nuclear ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Darlington NGS**[1]	31.4	26.5	30.3	34.6	34.8	35.5
2	**Pickering NGS**	129.6	147.1	156.4	127.5	133.0	143.0
3	**Nuclear Support Divisions**	34.1	29.7	27.7	27.3	25.3	29.4
4	**Asset Retirement Costs**	26.3	29.0	127.2	80.7	80.7	80.7
5	**Waste Management Variable Expenses**[2]	1.1	0.0	0.0	0.0	0.0	0.0
6	**Other**[3]	8.6	(3.7)	0.3	(0.0)	0.0	0.0
7	**Total**	231.1	228.6	341.9	270.1	273.7	288.5

Notes:

1 Includes the following amounts related to in-service additions for Darlington Refurbishment projects discussed in Ex. D2-2-1: 2012 Actual - $0.02M, 2013 Actual - $2.3M, 2014 Plan - $3.0M, 2015 Plan - $6.1M.

2 Amount for 2010 Actual is from Ex. C2-1-1 Table 2, line 5, col (a). Starting with 2011 Actual, low and intermediate level waste management variable expenses are included in nuclear base OM&A at Ex. F2-2-1 Table 1, as discussed in Ex. F4-1-1.

3 Includes losses on retirements, gains on sales and other related charges. Also includes asset removal costs for 2010 Actual. Starting with 2011 Actual, asset removal costs are included in nuclear OM&A, as discussed in Ex. F4-1-1.

Numbers may not add due to rounding.

Table 29
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Year Ending December 31 ,2013

Line No.	Particulars	Note	2013 Actual
			(a)
	Determination of Regulatory Taxable Income		
1	**Regulatory Earnings Before Tax**	1	(74.7)
	Additions for Regulatory Tax Purposes:		
2	**Depreciation and Amortization**		283.9
3	**Nuclear Waste Management Expenses**		25.1
4	**Receipts from Nuclear Segregated Funds**	2	44.7
5	**Pension and OPEB/SPP Accrual**		305.3
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance**	3	62.9
7	**Regulatory Liability Amortization - Income and Other Taxes Variance**		(18.7)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	4	78.9
9	**Taxable SR&ED Investment Tax Credits**		21.4
10	**Other**		19.6
11	**Total Additions**		823.2
	Deductions for Regulatory Tax Purposes:		
12	**CCA**		318.0
13	**Cash Expenditures for Nuclear Waste & Decommissioning**	5	104.7
14	**Contributions to Nuclear Segregated Funds**	6	98.1
15	**Pension Plan Contributions**	7	242.9
16	**OPEB/SPP Payments**		81.9
17	**Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account**		53.6
18	**SR&ED Qualifying Capital Expenditures**		0.0
19	**Other**		3.0
20	**Total Deductions**		902.3
21	**Regulatory Taxable Income** (line 1 + line 11 - line 20)		(153.8)
22	**Regulatory Income Taxes - Federal** (line 21 x line 26)		(23.1)
23	**Regulatory Income Taxes - Provincial** (line 21 x (line 27 + line 28))		(15.4)
24	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.7)
25	**Total Regulatory Income Taxes** (line 22 + line 23 + line 24)		(57.1)
	Income Tax Rate:		
26	**Federal Tax**		15.00%
27	**Provincial Tax**		11.00%
28	**Provincial Manufacturing & Processing Profits Deduction**		-1.00%
29	**Total Income Tax Rate**		25.00%

Notes:
1 Amount determined using the same methodology as discussed in Ex. C1-1-1, section 4.2 for historical years.
2 Ex. L-01.0.1 Staff-002, Attachment 1, Table 7, col. (a), line 17.
3 Ex. L-9.1-17 SEC-132, Attachment 1, Table 1, col. (e), line 19 plus line 20.
4 Ex. L-01.0.1 Staff-002, Attachment 1, Table 5, col. (d),line 7.
5 Ex. L-01.0.1 Staff-002, Attachment 1, Table 7, col. (a), line 7.
6 Ex. L-01.0.1 Staff-002, Attachment 1, Table 7, col. (a), line 16.
7 Represents the total of the Nuclear and Previously Regulated Hydroelectric pension plan contribution amounts shown in Ex. L-6.8-1 Staff-114 (c).

Table 30
Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs**[1]	111.9	226.1	345.5	374.6	379.7	371.4
2	**OPG-Wide Insurance**	16.9	16.1	16.2	16.3	19.0	19.5
3	**Nuclear Insurance**	7.3	8.1	11.5	7.6	12.9	14.7
4	**Performance Incentives**	47.8	38.0	28.2	20.4	29.1	29.1
5	**IESO Non-Energy Charges**	70.0	67.6	78.6	92.6	102.7	95.2
6	**Other**[2]	0.7	26.7	(4.5)	41.1	39.0	44.6
7	**Total**	254.6	382.6	475.5	552.6	582.4	574.5

Notes:
1 2010 amount is presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1.
2 2010 amount includes SR&ED Investment Tax Credits required by Canadian GAAP to be recorded in OM&A expenses, as discussed in Ex. F4-4-1, section 7.0 and Ex. A2-1-1.

Numbers may not add due to rounding.

Table 31
Allocation of Centrally Held Costs - Previously Regulated Hydroelectric ($M)

Line No.	Costs	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs[1]**	3.9	8.2	13.4	14.3	16.0	15.7
2	**OPG-Wide Insurance**	2.8	2.6	2.0	2.0	2.4	2.4
3	**Performance Incentives**	2.4	1.7	1.4	1.1	1.5	1.5
4	**IESO Non-Energy Charges**	10.1	2.7	3.3	2.9	5.0	5.0
5	**Other[2]**	0.4	0.7	(0.5)	0.4	1.2	1.4
6	**Total**	19.6	15.9	19.6	20.7	26.1	26.0

Notes:
1 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 1.
2 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 2.

Numbers may not add due to rounding.

Table 32

Allocation of Centrally Held Costs - Newly Regulated Hydroelectric ($M)

Line No.	Costs	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs[1]**	6.5	14.5	23.6	24.4	28.6	27.5
2	**OPG-Wide Insurance**	2.5	2.3	2.8	2.1	3.2	3.2
3	**Performance Incentives**	3.7	3.0	2.0	1.5	2.2	2.1
4	**IESO Non-Energy Charges**	6.3	4.1	5.5	4.4	8.8	8.7
5	**Other[2]**	0.0	1.2	(0.8)	(0.6)	6.8	7.2
6	**Total**	19.0	25.1	33.1	31.8	49.6	48.7

Notes:

1 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 1.

2 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 2.

Numbers may not add due to rounding.

Table 33
Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	Costs	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs**[1]	82.5	169.3	264.0	289.0	292.6	288.4
2	**OPG-Wide Insurance**	3.3	3.2	3.2	3.3	3.9	4.0
3	**Nuclear Insurance**	7.3	8.1	11.5	7.6	12.9	14.7
4	**Performance Incentives**	33.8	27.4	20.4	14.5	20.8	20.8
5	**IESO Non-Energy Charges**	35.2	37.9	45.4	57.4	60.2	59.6
6	**Other**[2]	(0.5)	21.2	(1.8)	38.1	27.8	32.3
7	**Total**	161.6	267.1	342.7	409.9	418.2	419.8

Notes:
1 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 1.
2 See Ex. L-01.0.1 Staff-002, Attachment 1, Table 30, Note 2.

Table 34

Other Revenues - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Revenue Source	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Ancillary Services[1]**	26.2	22.2	20.8	37.1	18.1	18.5
2	**Segregated Mode of Operation[2]**	(0.9)	1.7	(0.8)	4.1	0.0	0.0
3	**Water Transactions[3]**	5.5	7.5	1.6	1.0	1.7	1.7
4	**HIM Revenue Requirement Adjustment[4]**				6.5	N/A	N/A
5	**Subtotal**	30.8	31.5	21.6	48.6	19.9	20.2
	Newly Regulated Hydroelectric:						
	Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:						
6	**Ancillary Services**	26.4	26.1	25.9	35.7	22.7	23.1
7	**Segregated Mode of Operation**	0.0	0.0	0.0	0.0	0.0	0.0
8	**Subtotal**	26.4	26.1	25.9	35.7	22.7	23.1
9	**Total**	57.2	57.6	47.5	84.3	42.5	43.3

Notes:

1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-1-1.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).

4 Per the EB-2010-0008 Decision (p. 147) for 2011 and 2012 and EB-2012-0002 Payments Amount Order for 2013, 50% of Hydroelectric Incentive Mechanism (HIM) revenues are returned to ratepayers as an offset to the revenue requirement, with offset amounts of $5M and $7M identified for 2011 and 2012 Board Approved, respectively, and $6.5M for 2013. For the test period, OPG is proposing no offset be applied to the revenue requirement. For HIM Plan refer to Ex. E1-2-1 section 5.2.

5 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

Numbers may not add due to rounding.

Table 35
Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	NGD-Related Revenues:						
1	**Heavy Water Sales & Processing**	26.7	80.9	55.1	34.8	26.3	20.4
2	**Isotope Sales (Cobalt 60 + Tritium)**	10.1	4.8	11.5	7.0	11.6	11.9
3	**Inspection & Maintenance Services**	36.0	7.1	4.1	0.0	0.0	0.0
4	**Helium-3 Sales**	0.0	0.0	0.0	0.0	0.0	4.0
5	**Total NGD-Related Revenues**	72.8	92.9	70.6	41.8	38.0	36.3
6	**NGD-Related Direct Costs**	31.5	10.7	8.7	5.9	6.8	7.8
7	**NGD-Related Contribution Margin**	41.3	82.2	61.9	35.9	31.2	28.5
8	**Ancillary Services**[1]	2.6	2.4	1.8	1.7	1.9	1.9
9	**Other**	0.8	0.6	0.1	0.0	0.1	0.1
10	**Total**	44.7	85.1	63.8	37.6	33.2	30.5

Notes:
1 Ancillary Services related to Nuclear prescribed facilities are discussed in Ex. G1-1-1.

Table 36
Bruce Lease Net Revenues ($M)
Year Ending December 31, 2013

Line No.	Particulars	2013 Actual
		(a)
	Revenues:	
1	**Site Services (OPG to Bruce Power)**	0.6
2	**Low & Intermediate Level Waste Services**	5.3
3	**Cobalt-60**	0.6
4	**Total Services Revenue**	6.6
5	**Fixed (Base) Rent**	38.7
6	**Supplemental Rent - Non-Derivative Portion**	203.8
7	**Amortization of Initial Deferred Rent**	12.1
8	**Total Non-Derivative Rent Revenue**	254.6
9	**Total Non-Derivative Revenue** (line 4 + line 8)	261.2
10	**Supplemental Rent - Derivative Portion**	(32.8)
11	**Total Revenue** (line 9 + line 10)	228.4
	Costs:	
12	**Depreciation**	104.5
13	**Property Tax**	11.6
14	**Capital Tax**[1]	0.0
15	**Accretion**	369.0
16	**(Earnings) Losses on Segregated Funds**	(337.1)
17	**Used Fuel Storage and Disposal**	54.0
18	**Waste Management Variable Expenses and Facilities Removal Costs**	2.8
19	**Interest**	20.2
20	**Total Costs Before Income Tax**	225.0
21	**Income Tax - Current - Non-Derivative Portion**	26.9
22	**Income Tax - Deferred - Non-Derivative Portion**	(21.4)
23	**Total Income Tax - Non-Derivative Portion**	5.5
24	**Total Non-Derivative Costs** (line 20 + line 23)	230.5
25	**Income Tax - Current - Derivative Portion**	(26.9)
26	**Income Tax - Deferred - Derivative Portion**	18.7
27	**Total Income Tax - Derivative Portion**	(8.2)
28	**Total Costs** (line 24 + line 27)	222.3
29	**Bruce Lease Net Revenues - Non-Derivative Portion** (line 9 - line 24)	30.7
30	**Bruce Lease Net Revenues - Derivative Portion** (line 10 - line 27)	(24.6)
31	**Total Bruce Lease Net Revenues** (line 29 + line 30)	6.1

Note:
1 Capital tax was eliminated effective July 1, 2010.

Numbers may not add due to rounding.

Table 37

Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual
		(a)	(b)	(c)	(d)
1	**Opening Net Book Value**	1,073.2	854.9	1,316.7	1,963.4
2	**Add: Nuclear Liabilities Adjustments[2]**	(182.4)	495.1	725.6	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	35.8	33.2	78.9	104.5
5	**Closing Net Book Value**	854.9	1,316.7	1,963.4	1,858.9

Notes:

1 Includes Bruce asset retirement costs presented in Ex. C2-1-1 Table 3 and Ex. L-01.0.1 Staff-002, Attachment 1, Table 7.

2 Represents changes in Bruce asset retirement costs from Ex. C2-1-1 Table 3 (line 22 for 2010, line 26 for 2011, line 26 + line 27 for 2012).

Table 38
Calculation of Bruce Income Taxes ($M)
Year Ending December 31, 2013

Line No.	Particulars	Note	2013 Actual
			(a)
	Determination of Taxable Income		
1	**Earnings (Loss) Before Tax**	1	3.3
	Additions for Tax Purposes - Temporary Differences:		
2	**Base Rent Accrual**		42.3
3	**Depreciation**		104.5
4	**Accretion**		369.0
5	**Used Fuel and Waste Management Expenses and Faciities Removal Costs**		56.8
6	**Receipts from Nuclear Segregated Funds**		30.4
7	**Change in Fair Value of Bruce Derivative**		32.8
8	**Other**		2.5
9	**Total Additions - Temporary Differences**		638.4
	Deductions for Tax Purposes - Permanent Differences:		
10	**Deferred Rent Revenue**		14.2
	Deductions for Tax Purposes - Temporary Differences:		
11	**CCA**		5.7
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		91.3
13	**Contributions to Nuclear Segregated Funds**		85.9
14	**Earnings (Losses) on Nuclear Segregated Funds**		337.1
15	**Supplemental Rent Payment Reduction**		78.7
16	**Total Deductions - Temporary Differences**		598.6
17	**Taxable Income/(Loss) Before Loss Carry-Over**		29.1
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	2	(29.1)
19	**Taxable Income After Loss Carry-Over**		0.0
	Determination of Total Current Income Taxes		
20	**Taxable Income After Loss Carry-Over**		0.0
21	**Income Tax Rate - Current**		25.00%
22	**Income Taxes - Current**		0.0
	Determination of Total Deferred Income Taxes		
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)		37.9
24	**Income Tax Rate - Current**		25.00%
25	**Deferred Income Taxes - Short-Term**		(9.5)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)		1.9
27	**Income Tax Rate - Long-Term**		25.00%
28	**Deferred Income Taxes - Long-Term**		(0.5)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(29.1)
30	**Income Tax Rate - Current**		25.00%
31	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		7.3
32	**Deferred Income Tax - Total** (line 25 + line 28 + line 31)		(2.7)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes		
33	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		(78.7)
34	**Tax Loss Carry-Over From Prior Years - Impact of Derivative** (from line 18)	2	(29.1)
35	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 33 + line 34)		(107.7)
36	**Income Tax Rate - Current**		25.00%
37	**Income Taxes - Current - Derivative Portion**		(26.9)
38	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 37)		26.9
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes		
39	**Net Long-Term Temporary Differences - Impact of Derivative** (line 7 - line 15)		(45.8)
40	**Income Tax Rate - Long-Term**		25.00%
41	**Deferred Income Taxes - Long-Term - Derivative Portion**		11.5
42	**Tax Loss Carry-Over - Impact of Derivative** (line 34)		(29.1)
43	**Income Tax Rate**		25.00%
44	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		7.3
45	**Deferred Income Taxes - Total - Derivative Portion** (line 41 + line 44)		18.7
46	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 32 - line 45)		(21.4)
	Income Tax Rate - Current		
47	**Federal Tax**		15.00%
48	**Provincial Tax**		11.25%
49	**Provincial Manufacturing & Processing Profits Deduction**		-1.25%
50	**Total Income Tax Rate - Current**		25.00%
	Income Tax Rate - Long-Term		
51	**Federal Tax**		15.00%
52	**Provincial Tax**		10.00%
53	**Provincial Manufacturing & Processing Profits Deduction**		0.00%
54	**Total Income Tax Rate - Long-Term**		25.00%

Notes:

1. Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. L-01.0.1 Staff-002, Attachment 1, Table 36, line 11 and Total Costs Before Income Tax in Ex. L-01.0.1 Staff-002, Attachment 1, Table 36, line 20.
2. As noted in Ex. G2-2-1 Table 7, Note 4, the full amount of brought forward Bruce tax losses would be utilized in 2012 in the absence of the income tax deduction for the supplemental rent payment reduction in 2012. As such, no losses would be available for utilization in 2013.

Board Staff Interrogatory #003

Ref: Exh A1-4-3, CNSC Decision on Operating Licence for Pickering (August 9, 2013), O. Reg. 53/05

Issue Number: 1.0
Issue: General

Interrogatory

In the evidence at Exh A1-4-3 page 1, it states that, "In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station." Board staff notes that on August 9, 2013, the CNSC issued a one-site Power Reactor Operating Licence to OPG for the operation of the Pickering Nuclear Generating Station.

The prescribed generation facilities as listed in O. Reg. 53/05 refer to Pickering A and Pickering B. Please reconcile the change in overall operations of Pickering with O. Reg. 53/05.

Response

There is no issue requiring reconciliation. O. Reg. 53/05 sets out the list of OPG facilities that were prescribed by the Province on April 1, 2008. The subsequent operational amalgamation of Pickering A and Pickering B has no legal or practical impact on the economic regulation of OPG by the OEB, since the facilities are in fact the same facilities that were originally designated.

AMPCO Interrogatory #001

Ref: Exhibit A1, Tab 3, Schedule 2 Drivers of Deficiency, Pages 5 & 6

Issue Number: 1.0
Issue: General

Interrogatory

Please update Chart 1 on Page 5 and Chart 2 on Page 6 to reflect the proposed changes identified in the Impact Statement at Exhibit N1, Tab 1, Schedule 1.

Response

The requested updated charts follow.

DRIVERS OF DEFICIENCY

Chart 1
Previously Regulated Hydroelectric, 2014-2015 Test Period
Updated to Reflect the Impact Statement (Ex. N1-1-1)

	($M)	**Notes** *(updated comments in Italic)*
EB-2010-0008 Approved Revenue Requirement	**1,419.2**	Ex. I1-1-1, Table 2 ***(no change)***
Increase in Cost of Capital	133.8	Higher forecasted long-term debt costs and ROE due to increased rate base as a result of the Niagara Tunnel project coming into service ***(no change)***
Increase in OM&A	39.3	Increases in Base OM&A (Ex. F1-2-1, Ex. F1-2-2) and Project OM&A (Ex. F1-3-2) ***(rise in the Allocation of Centrally Held Costs due to increased Pension/OPEB Costs)***
Increase in Depreciation & Amortization	33.4	Primarily due to the Niagara Tunnel project coming into service (Ex. F4-1-1) ***(no change)***
Decrease in Ancillary and Other Revenue	36.3	Lower operating reserve market prices and lower regulation service revenues (Ex. G1-1-1 and Ex. G1-1-2) ***(increased Ancillary Services revenue)***
Increase in Income Taxes	56.5	Increased Regulatory Taxable Income, mainly due to higher rate base due to the Niagara Tunnel coming into service (Ex. F4-2-1, Table 5) ***(increased Pension/OPEB Costs)***
Other	21.2	Includes differences in Property Taxes and Gross Revenue Charge ***(increased GRC due to higher forecast production levels)***
Total Change in Revenue Requirement	**320.5**	
Proposed Revenue Requirement for 2014 – 2015 Test Period	**1,739.7**	Ex. N1-1-1, Table 1
Revenue at Current Rates	**1,471.1**	Using forecast production levels for the test period ***(41.1 TWh) (higher forecast production due to increase in water availability)***
Revenue Requirement Deficiency	**268.6**	Ex. N1-1-1, Table 4

Chart 2
Nuclear Deficiency, 2014-2015 Test Period
Updated to Reflect the Impact Statement (Ex. N1-1-1)

	($M)	**Notes** *(updated comments in Italic)*
EB-2010-0008 Approved Revenue Requirement	**5,251.5**	Ex. I1-1-1, Table 3 ***(no change)***
Decrease in Cost of Capital	(56.1)	Lower long-term debt costs and ROE ***(no change)***
Increase in the Allocation of Centrally Held Costs	468.0	Primarily due to an increase in pension and OPEB costs (Ex. F4-4-1) **(*increased Pension/OPEB Costs*)**
Increase in Outage OM&A	177.5	Mainly due to the 2015 Vacuum Building Outage (Ex. F2-4-2) ***(no change)***
Increase in the Allocation of Support Services Costs	349.8	Due to the transfer of nuclear functions to centre-led corporate groups as part of BT, offset by similar reduction in nuclear costs (Ex. F3-1-2) ***(no change)***
Decrease in Base OM&A	(120.4)	Transfers of costs to corporate groups partially offset by labour cost escalation and higher pension and OPEB costs (Ex. F2-2-1) ***(no change)***
Increase in Depreciation & Amortization	70.5	Increase in Asset Retirement Cost due to ONFA (Ex. F4-1-1) ***(no change)***
Decrease in Bruce Lease Net Revenues	190.8	Increase in Bruce Costs is primarily due to ONFA (Ex. G2-2-1) ***(no change)***
Increase in Income Taxes	86.1	Higher regulatory taxable income is primarily due to pension and OPEB costs (Ex. F4-2-1, Table 5) ***(decreased due to higher Pension/OPEB Costs)***
Other	231.3	Includes the EB-2010-0008 compensation disallowance of $145M as well as differences in Fuel, Property Taxes, other OM&A Costs and Ancillary and Other Revenue **(*increase due to higher Pension/OPEB Costs offset by lower nuclear fuel costs*)**
Total Change in Revenue Requirement	**1,397.3**	
Proposed Revenue Requirement for 2014 – 2015 Test Period	**6,648.8**	Ex. N1-1-1, Table 1
Revenue at Current Rates	**4,900.2**	Using forecast production levels for the test period **(*95.1 TWh*) *(lower forecast production)***
Revenue Requirement Deficiency	**1,748.6**	Ex. N1-1-1, Table 4

AMPCO Interrogatory #002

Ref: Exhibit A1, Tab 6, Schedule 1, Attachment 3 Proposed Amendment to O. Reg. 53/05

Issue Number: 1.0
Issue: General

Interrogatory

a) Please provide the status of the proposed amendment to O. Reg.53/05.

b) Please discuss OPG's stakeholder consultations regarding the proposed amendments.

Response

a) O.Reg. 53/05 was amended by O. Reg. 312/13 on November 29, 2013 and published in the Ontario Gazette on December 14, 2013. The finalized version of O. Reg. 53/05 has been included as Attachment 1 to this response.

b) The proposed amendments to O. Reg. 53/05 were posted for public comment by the Government on the Regulatory Registry from September 13, 2013 to October 28, 2013 (see Ex. A1-6-1, Attachment 3). OPG did not conduct any stakeholder consultations concerning the proposed amendments.

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05
PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From November 29, 2013 to the e-Laws currency date.

Last amendment: O. Reg. 312/13.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Note: On July 1, 2014, section 0.1 is amended by adding the following subsection: (See: O. Reg. 312/13, ss. 1, 6)

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
    i. Sir Adam Beck I.
    ii. Sir Adam Beck II.
    iii. Sir Adam Beck Pump Generating Station.
    iv. De Cew Falls I.
    v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Note: On July 1, 2014, section 2 is amended by adding the following paragraph: (See: O. Reg. 312/13, ss. 2, 6)

6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in the Schedule.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.
2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Note: On July 1, 2014, section 4 is revoked. (See: O. Reg. 312/13, ss. 3, 6)

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Note: On July 1, 2014, section 5.1 is revoked. (See: O. Reg. 312/13, ss. 3, 6)

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Note: On July 1, 2014, section 5.3 is revoked. (See: O. Reg. 312/13, ss. 3, 6)

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

Note: On July 1, 2014, paragraph 7 is amended by striking out the portion before subparagraph i and substituting the following: (See: O. Reg. 312/13, ss. 4 (1), 6)

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

   i. return on rate base,

   ii. depreciation expense,

   iii. income and capital taxes, and

   iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

Note: On July 1, 2014, paragraph 7.1 is amended by striking out the portion before subparagraph i and substituting the following: (See: O. Reg. 312/13, ss. 4 (2), 6)

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

Note: On July 1, 2014, subsection (2) is amended by adding the following paragraph: (See: O. Reg. 312/13, ss. 4 (3), 6)

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

Note: On July 1, 2014, the Regulation is amended by adding the following Schedule: (See: O. Reg. 312/13, ss. 5, 6)

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.

19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5.

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AMPCO Interrogatory #003

Ref: Exhibit A1, Tab 4, Schedule 1, Attachment 2, Memorandum of Agreement

Issue Number: 1.0
Issue: General

Interrogatory

Section E – Communication and Reporting: Please confirm OPG has met Shareholder expectations with respect to communication and reporting.

Response

Confirmed.

CCC Interrogatory #001

Ref: Exhibit A1/T2/S2

Issue Number: 1.0
Issue: General

Interrogatory

Please provide an update to the above-referenced exhibit, labeled "Approvals", that reflects the December 6, 2013 update. In effect, please explain how the approvals sought have changed as a result of the update.

Response

The requested update to Ex A1-2-1, "Approvals", is included as Attachment 1 to this response.

APPROVALS

Updated to reflect Dec 6, 2013 Impact Statement

In this Application, OPG is seeking the following specific approvals:

- The approval of a revenue requirement of $1,739.7M for the previously regulated hydroelectric facilities and a revenue requirement of $6,648.8M for the nuclear facilities for the period of January 1, 2014 through December 31, 2015 as set out in Ex. N1-1-1.

- The approval of an 18 month revenue requirement of $853.4M for the newly regulated hydroelectric facilities for the period of July 1, 2014 through December 31, 2015, calculated as one half of a 2014 revenue requirement of $555.2M plus a 2015 revenue requirement of $575.8M, as set out in Ex. N1-1-1.

- The approval of a rate base of $5,128.0M and $5,084.6M for the previously regulated hydroelectric facilities for the years 2014 and 2015, respectively; a rate base of $2,511.5M and $2,528.2M for the newly regulated hydroelectric facilities for the years 2014 and 2015, respectively; and $3,706.7M and $3,659.0M for the nuclear facilities for the years 2014 and 2015, respectively, as summarized in Ex. B1-1-1.

- Approval of a production forecast of 41.1 TWh for 2014 and 2015 for the previously regulated hydroelectric facilities, a production forecast of 17.9 TWh for July 1, 2014 to December 31, 2015 for the newly regulated hydroelectric facilities; and 95.1 TWh for 2014 and 2015 for the nuclear facilities. The production forecasts are presented in Ex. E1-1-1 and Ex. E2-1-1 and updated in Ex. N1-1-1.

- Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the Board's Cost of Capital Report, and currently forecast at 8.98 per cent for 2014 and 2015, as presented in Ex. C1-1-1.

- Approval of a payment amount for the previously regulated hydroelectric facilities, of $42.31/MWh effective January 1, 2014 for the average hourly net energy production (MWh) from the previously regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the previously regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the previously regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N1-1-1.

- Approval of a payment amount for the newly regulated hydroelectric facilities, of $47.59/MWh effective July 1, 2014 for the average hourly net energy production (MWh) from the newly regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the newly regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the newly regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N1-1-1.

- Approval of a payment amount for the nuclear facilities, of $69.91/MWh effective January 1, 2014.

- Approval for recovery of the audited December 31, 2013 balances of the Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Capacity Refurbishment-Hydroelectric variance accounts for the previously regulated hydroelectric facilities, currently projected to be $120.1M, as described in Ex. H1-1-2 and disposition, beginning January 1, 2015, at a rate of $2.99/MWh applied to the output from the previously regulated hydroelectric facilities.

- Approval for recovery of the audited December 31, 2013 balance of the Nuclear Development Variance Account and a portion of the balance of the Capacity Refurbishment Variance Account - Nuclear for the nuclear facilities, currently projected to be $73.1M as described in Ex. H1-2-1 and disposition, beginning January 1, 2015, at a rate of $1.59/MWh applied to the output from the nuclear facilities.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
    - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
    - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
    - A variance account to record the financial impact of foregone production at its regulated hydroelectric facilities due to surplus baseload generation.
    - A variance account to record interest and amortization of the accumulations up to year end 2013 of 50 per cent of the Hydroelectric Incentive Mechanism net revenues above amounts underpinning the EB-2010-0008 revenue requirement as a credit to ratepayers, proposed to be terminated December 31, 2015.
    - A variance account to record the deviation from forecast capital and non-

capital costs and firm financial commitments associated with work to increase the output of, refurbish or add operating capacity to a regulated facility.

- A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities.
- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses, to be terminated December 31, 2014.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities and associated tax effects.
- A variance account to capture depreciation cost differences due to a revised service life, for accounting purposes, of the Pickering nuclear facility.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- A deferral account to record the transition and implementation impacts associated with the adoption of the Generally Accepted Accounting Principle of the United States ("USGAAP"), to be terminated December 31, 2014.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-3-1.

- In respect of the Darlington Refurbishment Project ("DRP") OPG seeks the following as described in Ex. D2-2-1:
    - A finding that OPG's commercial and contracting strategies for the DRP are reasonable;
    - A finding that the proposed capital expenditures of $837.4M in 2014 and $631.8M in 2015 are reasonable;
    - Approval of OM&A expenditures of $19.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1);
    - Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense; and
    - Approval to recover the capital cost portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013, currently projected at $3.7M.

- An order from the OEB declaring OPG's current payment amounts for previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, if the order or orders approving the payment amounts are not implemented by January 1, 2014.

- An order from the OEB declaring OPG's current payment amounts for the newly regulated hydroelectric facilities interim as of July 1, 2014, if the order or orders approving the payment amounts are not implemented by July 1, 2014.

CCC Interrogatory #002

Ref:

Issue Number: 1.0
Issue:

Interrogatory

Please explain how OPG undertakes "customer engagement activities". To what extent does OPG consider the views of Ontario consumers with respect to its operations beyond those related to rate impacts? How does OPG assess what rate impacts for end-use consumers are appropriate?

Response

OPG has no direct "customers", but maintains ongoing engagement with officials in all of our host communities. This includes regular conversations with Mayors, MPs and MPPs, councilors, business leaders and associations and members of the community via community councils.

At the provincial level, OPG is involved in a number of provincial organizations and has regular engagement with MPPs and energy critics, and groups such as the Canadian Manufacturers and Exporters, AMPCO, Ontario Chamber of Commerce and Ontario Mining Association.

OPG uses its business planning process to focus on cost reductions and efficiencies. This focus has a direct positive impact on customer bills and is reinforced through initiatives like Business Transformation. As indicated previously by the OEB, it is up to OPG to plan for the requirements of its business and to propose payment amounts that represent an efficient and reasonable level of costs. The final assessment of these proposals and the resulting rates is up to the OEB.

CCC Interrogatory #003

Ref: Ex. A1/T4/S2/p. 8

Issue Number: 1.0
Issue: General

Interrogatory

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the US, federal and provincial legislation and regulatory requirements, as well as several contractual arrangements with third parties. The evidence states that collectively, these result in additional costs and program needs with respect to the operation and management of the regulated facilities. Please explain to what extent, if at all, any of these treaties, legislation, regulatory requirements or contractual arrangements has changed since OPG's last application to the OEB. To the extent they have changed please explain the impact of the changes on the revenue requirements in each year.

Response

O. Reg. 53/05 was amended by O. Reg. 312/13 to include 48 newly regulated hydroelectric generation stations to OPG's prescribed assets. There have been no other significant changes in the treaties, legislation, regulatory requirements, or contractual arrangements pertaining to OPG's regulated hydroelectric facilities since OPG's last application (EB-2010-0008).

Ex. I1-1-1, page 1, lines 15 - 18 sets OPG's revenue requirements for the newly regulated hydroelectric generation stations.

CME Interrogatory #001

Ref: 2013 Annual Report of the Office of the Auditor General of Ontario (December **10,** 2013)

Issue Number: 1.0
Issue: General

Interrogatory

CME wishes to better understand the process undertaken by OPG following the release of the Annual Report of the Office of the Auditor General of Ontario on December 10, 2013. To this end:

(a) Please provide all presentations, PowerPoint slides, briefing notes, or other written memoranda prepared by OPG for OPG's Board of Directors relating to that Report of the Auditor General; and

(b) Please provide all written questions, comments or directions provided by OPG's Board of Directors to OPG relating to that Report of the Auditor General.

Response

Attachment 1 summarizes OPG's ongoing actions in response to the Auditor General's Report.

The Auditor General's Report was issued months after OPG filed its Application and after the filing of OPG's Impact Statement.

Therefore, any attempt to link the potential outcomes from these responsive actions to changes in OPG's 2014 -2015 costs would be speculative at this point. Many of the actions are still being developed. Moreover, full implementation of these actions would require changes in OPG's collective agreements. Even for non-represented employees, notice may be required before the most significant changes could be made. Thus, OPG declines to produce the requested materials on grounds of relevance.

Filed: 2014-03-19
EB-2013-0321
Exhibit L
Tab 1.0
Schedule 3 CME-001
Attachment 1

ONTARIO POWER GENERATION

Backgrounder
from Ontario Power Generation

700 University Avenue Toronto, ON M5G 1X6
Tel: 416-592-4008 or 1-877-592-4008
www.opg.com

Dec. 10, 2013

OPG SUMMARY OF KEY ACTIONS
2013 AUDITOR GENERAL REPORT ON HUMAN RESOURCES POLICIES

The Auditor General's report covers a 10-year time period. In some cases the report highlights areas which OPG already had identified and has since addressed, or is currently addressing. In other areas it provides insights into issues the company will act upon and will report back openly and quickly.

In 2010 OPG initiated a business transformation to address culture and process change to ensure OPG meets the expectations and needs of the ratepayers. Since December 2012 the number of senior managers has gone down by six per cent, and since 2010, there's been a nine per cent drop in total base salary costs for management. We will also save an estimated $1 billion over six years (2011-2016) by reducing the overall headcount, from ongoing operations, by 2,330 or 20 per cent of 2011 levels. The departure of 1,500 people since January 2011 has already saved $275 million.

We are continuing that transformation, which was recognized by KPMG as the right way to address the needed change. The Ministry of Energy engaged KPMG to assess OPG's existing benchmark studies and to identify organization and structural opportunities for cost savings. KPMG's report validated OPG's business transformation initiative and its objectives.

"KPMG believes that OPG has employed a systematic and structured approach to developing a company-wide transformation plan. OPG has incorporated many leading practices for implementing a large business transformation such as assigning dedicated staff to implement the transformation, establishing a program management office, incorporating change management with a focus on cultural change and incorporating business transformation milestones into executive performance plans." KPMG Dec. 6, 2012.

The following is a summary of key actions OPG is taking (or has taken) to address the findings. A more detailed list of actions will be posted on our website later this week. In the coming weeks and months it will be updated to show our progress.

ACTIONS – PLANNED AND UNDERWAY	*PLANNED COMPLETION DATE*
Executive and Senior Management Staffing Levels	
• Decrease senior management headcount in proportion to overall headcount reductions. (Reduced by 6% since Dec. 2012).	2016
• New senior executives continue to receive lower	Ongoing

compensation than their predecessors. Hiring of all director and above positions will require CEO approval. • Reduce headcount by a further 830, for a total reduction of 2,330 and $1B savings by 2016.	 2016
Benchmarking of Staffing Levels at Nuclear Facilities • Business plans to define continuing actions to move from current 8% over benchmark to benchmark (down from 17% over in Feb. 2012). • CNSC and other external peer groups confirm OPG continues to ensure strong nuclear safety and operational performance.	2016 Ongoing
Recruitment Practices and Requirements • Centralized recruitment function to improve controls, compliance and efficiency of hiring processes. • Amend Code of Conduct to clarify expectation regarding hiring policies. Failure to follow policy will result in disciplinary action. • Conduct compliance reviews for internal/external vacancies. • Reviewed all groups with same addresses to ensure valid hiring process was followed.(reviewed 284 files from 2011, 2012; no documentation retained for others beyond two years; found 4 cases without proper documentation).	Complete Q1 2014 Ongoing Complete
Compensation and Incentive Awards • Implement outcomes of government legislation to regarding broader public sector executive compensation. • Reduce headcount by additional 830 for total reduction of 2,330 and $1B savings by 2016 (already achieved 1,500 reduction since Jan. 2011); • Reduce all management AIP for 2013 by 10%. Board to review AIP program for 2014 and beyond. • Continue to seek collective agreements that reflect OPG business objectives and government compensation constraints. • Reduced base salary costs for management by 9%	Contingent on government legislation 2016 Q1 2014 Ongoing Completed. Further reductions ongoing.

compared to 2010.	
Employee Housing and Moving Allowance • Adopt Ontario Public Service Relocation policy for management employees. • Conduct review of practices and controls related to employee relocation, including a review of practices for guarantee house values. • Review OPS relocation policy against collective agreements to determine what if any changes are required.	Q1 2014 Q1 2014 Coterminous with collective bargaining
Security Clearance Requirements • Review security clearance requirements for non-nuclear employees to ensure appropriate levels in place. • Implement enhanced compliance monitoring method. • Implemented controls to ensure immediate security clearance compliance for new hires and ongoing compliance for existing employees. • CNSC, CSIS audits validate that OPG has an industry-leading nuclear security clearance program. All employees who require access to nuclear site or sensitive nuclear information have appropriate clearance. All board members at the time of the AG audit now have security clearance.	Q1 2014 Q3 2014 Complete
Pensions and Benefits • Begin implementation of Board directed management pension and benefits reforms. • Participate in Province's review of electricity sector pension plan reforms. • Any changes to pension and benefits for unionized staff will be a matter for future rounds of collective bargaining.	Q1 2014 TBC – dependent on Ministry of Finance Coterminous with collective bargaining
Managing Contractors and Overtime • Conduct comprehensive assessment of contractor control framework, including contract structures, time capture and approval processes and tools. • Implement time tracking system for contractors at nuclear sites.	Q2 2014 Q1 2014

• Implemented enhanced management process approvals and controls to limit individual overtime in Nuclear.	Completed
Use of Non Regular Staff and Contract Resources • Strengthen business case requirements and approvals for hiring retirees as contractors. • Strengthen succession planning and develop knowledge transfer plans for critical roles.	Q2 2014 Q4 2014

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For more information, please contact:

Ontario Power Generation
Media Relations
416-592-4008 or 1-877-592-4008
Follow us @ontariopowergen

SEC Interrogatory #001

Ref: A2-1-1-Attach 1/p.23

Issue Number: 1.1
Issue: Has OPG responded appropriately to all relevant Board directions from previous proceedings?

Interrogatory

The Applicant says, in its 2012 Annual Report:

> *"OPG is currently exploring long-term revenue options to recover its costs and earn an appropriate return, while moderating customer rates."*

Please provide details of this initiative to explore such options, including a list of all such options considered, and the analysis of their feasibility. Please provide any documents that describe or provide information on this initiative, and on the options available to the Applicant to increase revenues. Please provide any presentations to the Applicant's board of directors related to this initiative.

Response

The entire quote from OPG's 2012 Annual Report (Ex. A2-1-1, Attachment 1 at page 23) from which the referenced sentence is taken reads as follows:

> Electricity produced from the Prescribed Facilities, nuclear and most of its baseload hydroelectric generating stations, receives regulated prices. Under the current regulatory framework, OPG's objective is to clearly demonstrate that its regulated costs are prudently incurred and should be fully recovered, while OPG earns an appropriate return. The OEB's decision on OPG's application for new regulated prices effective March 1, 2011 established significantly lower regulated prices than submitted by OPG. As such, the regulated prices do not fully reflect the recovery of the costs of the regulated operations and do not allow these operations to earn an appropriate rate of return, thereby negatively impacting OPG's financial performance. In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. In 2013, OPG plans to file an application with the OEB for new regulated prices for production from its Prescribed Facilities, effective in 2014. OPG is currently exploring long-term revenue options to recover its costs and earn an appropriate return, while moderating customer rates.

The long-term revenue options referred to are the requested payment amounts for the prescribed facilities including the newly prescribed hydroelectric facilities discussed throughout

OPG's Application. Similarly, the efforts to moderate customer rates are the ongoing cost control initiatives discussed throughout the Application including Business Transformation. Please refer to Ex. L-04.7-1 Staff-045 for a discussion of OPG's long term rate smoothing strategy. With regard to documents presented to the OPG Board of Directors regarding this application, see Ex. L-1.4-17 SEC-020.

Board Staff Interrogatory #004

Ref: Exh A2-2-1 Attachment 1 and Attachment 2, Exh N-1-1 Attachment 4

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

OPG filed the 2014-2015 payment amounts application on September 27, 2013. In the evidence at Exh A2-2-1 Attachment 2, the 2013-2015 Business Planning Instructions were filed. Those instructions, dated July 20, 2012, provide context, guidelines, key process changes and a schedule in addition to instruction. The schedule at page 9 of the document lists 2012 activities from June to December and indicated that OPG Board approval of the 2013-2015 Business Plan was scheduled for November 15.

a) The 2013-2015 Business Plan was filed at Exh A2-2-1 Attachment 2. The 2013-2015 Business Plan is dated May 16, 2013. The recommendation for submission to the OPG Board states that the Business Plan incorporates the OM&A and capital plans provided to the Board in November 2012. What are the reasons for the delay in finalizing the 2013-2015 Business Plan?

b) On December 6, 2013, OPG filed Exhibit N to show the impact of certain material changes resulting from OPG's 2014-2016 Business Plan. That Business Plan was filed as Attachment 4 and is dated November 14, 2013. Please file the 2014-2016 Business Planning Instructions.

Response

a) Certain significant revenue assumptions were not finalized in time for the scheduled approval of the 2013 – 2015 Business Plan in November 2012. These included assumptions regarding OPG's nuclear payment amounts applications. OPG previously noted in EB-2012-0002, Ex. L-4-1 Staff-29 filed on December 7, 2012 that it was considering the timing and approach for a rate application for its nuclear facilities.

   Since budgets for 2013 were required prior to the start of 2013, these were tabled with the OPG Board in December 2012 and approved for budget control purposes. Once the significant revenue assumptions were finalized, the full 2013 - 2015 Business Plan was tabled with and agreed to by the OPG Board in May 2013.

b) A redacted copy of the 2014 - 2016 Business Planning Instructions is provided as Attachment 1 to this response. A confidential version will be filed in accordance with the OEB's practice direction on confidential filings.

2014-2016
Business Planning
Instructions

Issued by:
Controllership – Business Planning and Reporting

Issued – July 11, 2013

ONTARIO POWER GENERATION

CONTACT INFORMATION

If you require further information on business planning assumptions, schedules, or requirements, please contact:

John Mauti – Vice-President, Business Planning & Reporting	400-4046
Alex Kogan – Director, Business Planning & Performance Reporting	400-3103
Sandra Radcliffe – Senior Manager, Financial Forecasts	400-4062

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1.0 BUSINESS PLANNING CONTEXT

CONTACT: ANDREW TEICHMAN

As OPG begins the 2014-2106 business planning cycle, it continues to face a challenging outlook due in part to:

- Not having had an increase in regulated base rates for the currently regulated facilities since 2008;
- Continuing weak wholesale prices for the currently unregulated, non-contracted hydroelectric output;
- [redacted]
- The impact of pension and other benefit costs and funding requirements, which are subject to significant volatility as discount rates and other economic factors change; and
- Increasing capital expenditures driven primarily by Darlington refurbishment.

In the face of these challenges, OPG has demonstrated strong operational and project development performance in recent years. These accomplishments include:

- Strong performance of Darlington operations, including an overall decline in nuclear production unit energy costs over the past 3 years;
- Implementation of the Business Transformation initiative, driving cost reductions and implementing additional efficiencies while transforming OPG into a more competitive and scalable organization;
- Reductions in headcount from ongoing operations of ~1,000 in 2011/2012 with a targeted reduction of ~2,000 by 2015; and
- Successful completion of major projects, including the recent completion of the Niagara Tunnel.

With respect to the external environment, the economic outlook for the Province remains mixed, with a prospect of an extended period of uncertainty. At the same time, with the need for new energy supply winding down, competition is intensifying. The Province has embarked on an initiative to review the Long-Term Energy Plan (LTEP) which will focus on Ontario's long-term electricity supply mix.

Given this context, OPG needs to remain vigilant in continuing to pursue its key strategic objectives of: 1) operational excellence; 2) project excellence; and 3) financial sustainability.

Business Transformation (BT) continues to be a key initiative that is expected to yield additional operating efficiencies and flexibility over the next several years. The initiative must be successfully implemented without compromising the operation of the generating plants in a safe, reliable and environmentally responsible manner (refer to section 5.9 for instructions on budgeting for specific BT initiatives). Generation development projects also need to continue to be delivered on time and on budget. With the expected completion of the [redacted] and [redacted] projects over the 2014-2015 period, increased focus is shifting to Darlington Refurbishment, as preparation work and detailed project planning are finalized. From a revenue perspective, OPG needs to address revenue shortfalls for the currently unregulated, non-contracted hydroelectric generation, file a base rate application with the Ontario Energy Board (OEB) for the currently regulated assets in order to reflect current cost and production levels, and work to achieve greater certainty with respect to cost recovery for Darlington Refurbishment. Delivering on these and other key initiatives will support OPG's mission of being Ontario's low-cost generator of choice.

1.1 REGULATED REVENUE ASSUMPTIONS

CONTACT: COLIN ANDERSON

OPG's currently regulated operations include most of OPG's baseload generation facilities and represent at least 80% of OPG's total generation output. As such, these facilities provide a relatively stable earnings contribution. However, OPG has not received an increase on its regulated base rates since 2008. Combined with the significant decline of Ontario spot market prices which has affected earnings from OPG's currently unregulated, non-contracted hydroelectric generating assets, this has put strains on OPG's earnings and cash flows.

In order to improve its financial outlook, in the fall of 2013, OPG expects to file a cost-of-service application with the OEB for new base rates and riders for generation from the currently regulated hydroelectric and nuclear facilities. The application will cover two years, 2014 and 2015. The new base rates and riders are expected to be effective January 1, 2014. The application will be based on the 2013-2015 Business Plan

(2013-2015 BP). The application will be updated for material differences in the 2014-2016 Business Plan (2014-2016 BP) impacting the 2014 and 2015 years.

The 2014-2016 BP will also assume rate regulation of all of OPG's unregulated, non-contracted hydroelectric generating assets effective January 1, 2014. OPG is the only entity that currently receives Ontario spot market electricity prices. Low spot market prices have resulted in revenues that are insufficient to recover the costs of operations and provide an adequate return on these assets. OPG's application with the OEB in the fall of 2013 is expected to include a cost-of-service rate request for these newly regulated assets.

[redacted]

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

[redacted]

1.1.1 Incentive Rate-Making

In March 2013, the OEB issued a report setting out its expectations for applying incentive rate-making (IRM) to OPG's regulated operations. For OPG's nuclear assets, the OEB expects OPG to move to a multi-year cost-of-service approach (i.e., 3-5 years) beginning in 2016. For OPG's regulated hydroelectric assets, the OEB expects that OPG will move to a form of IRM after 2015. The OEB also expects to establish working groups with stakeholders to develop the details of these two approaches. The current expectation is that these working groups will begin their work in Q3 2014, following the decision on OPG's 2014-2015 application. The 2014-2016 business planning process will be used as a basis for developing the financial and operational information necessary to support the work of the working groups.

OPG's rate applications covering the 2016-2020 period are expected to be based on the next business plan, for the post-2014 period, and will reflect the OEB's direction following the recommendations of the working groups. The planning horizon and requirements for the next business plan will be informed by the development of the details of the IRM regulatory approaches through the working group process.

1.2 OPERATING AND INVESTMENT ASSUMPTIONS — CONTACT: ALEX KOGAN

The operating and investment assumptions that currently form the planning basis for the 2014-2016 BP are as follows:

Nuclear Operations – Pickering

- Pickering units will operate to 247K equivalent full power hours (P1, 4, 7 & 8 end-of-life in 2020; P5 & 6 in 2019) reflecting the Continued Operations initiative
- The ***Pickering Unit 7 Life Management*** outage will take place starting in 2016

Nuclear Operations – Darlington

- The ***Darlington Vacuum Building Outage*** (VBO) will take place in the spring of 2015, with subsequent VBOs taking place over a 12-year cycle with no further Station Containment Outages
- Darlington units will operate to approximately 210K equivalent full power hours prior to refurbishment

Nuclear Operations – Nuclear Waste Management

- The ***Low & Intermediate Level Waste Deep Geologic Repository (L&ILW DGR)*** will be placed in-service within 5-7 years of receipt of a construction licence and approval by the OPG Board of Directors
- The 2014-2016 BP will continue to reflect the current waste minimization and reduction program focused on the efficient management of nuclear waste material currently in storage and at the sites. The work program is required to manage the waste until the in-service of the L&ILW DGR, without the construction

of new facilities. The work program is expected to be funded internally from the nuclear waste management provision.

Darlington Refurbishment

- Darlington Refurbishment outages will commence in October 2016 with Unit 2
- Each unit outage will have a duration of 36 months
- The outage to refurbish the second unit (Unit 1) will commence upon completion of work on Unit 2
- The total duration of the outages for all four units will be 108 months

Nuclear New Build

- A decision on Nuclear New Build is expected by the Province in 2014, following the analysis of Service Agreement deliverables by the end of 2013. The 2014-2016 BP will only reflect OM&A costs necessary to preserve the option for future development, including CNSC licensing fees and support for the Province's decision process. No capital costs will be included.

Hydroelectric Development

[redacted]

- The project execution phase for the ***Ranney Falls*** expansion will commence in 2015, with the project placed in-service in 2017. Ranney Falls GS will be included in newly regulated hydroelectric assets.

[redacted]

- The project execution phase for the ***SAB PGS Reservoir Rehabilitation*** will start in 2016, to be placed in-service in 2017. The project will be part of the currently regulated hydroelectric assets.
- [redacted] and ***Lake Gibson*** development projects will not be included in the 2014-2016 BP

Thermal Operations and Unit Conversion Opportunities

[redacted]

[redacted]

Support Services

- The ***Enterprise Systems Consolidation Project*** will be placed in service in 2015 (see section 5.6.1 for additional information)

2.0 RESOURCE GUIDELINES

CONTACT: SANDRA RADCLIFFE

As described in section 1.0, OPG continues to face challenges on its planning horizon. OPG's previous business plans responded to these challenges by committing to reduced headcount levels, based on attrition, in recognition of expected changes in capacity and production. The resource guidelines for the 2014-2016 BP reaffirm these commitments. .

The ***guidelines for headcount*** and ***total OM&A from ongoing operations for 2014 and 2015*** outlined below are consistent with the approved 2013-2015 BP, as adjusted to reflect subsequent budget transfers and the current organizational structure as of June 1, 2013. The ***guidelines for headcount*** and ***total OM&A from ongoing operations for 2016*** outlined below reflect an updated attrition forecast and economic factors. Organizational changes resulting from the current redeployment process will be addressed through budget transfers during 2014, as needed. The guidelines for Darlington Refurbishment are to be treated as preliminary at this time. It is recognized that the Nuclear Operations headcount and total OM&A guidelines may need to be reviewed, as resource requirements for the Darlington Refurbishment (e.g., swing staff) are defined further.

As noted in section 1.1, Nuclear New Build OM&A guidelines reflect costs necessary to preserve the option for future development. No separate headcount guideline is provided for Nuclear New Build for the current plan, as the previously dedicated resources are now embedded in various groups across the organization and, therefore, are reflected in the guidelines for those groups. Refer to section 5.7 for a discussion of allocation of resources in support of Nuclear New Build.

[redacted]

2014-2016 Headcount Guidelines

	Budget*	Guideline		
	2013	2014	2015	2016
Nuclear Operations	5,727	5,588	5,477	5,450
Nuclear Projects (Excl. Darlington Refurbishment)	341	337	333	315
Hydro-Thermal Operations	[redacted]			
CO&E	176	165	153	140
Total Operations	[redacted]			
Business and Administrative Services	1,047	988	932	855
Finance	361	335	308	295
People & Culture	620	593	570	550
Corporate Office	118	111	107	105
Law	23	23	23	22
Executive Office	10	10	9	9
Total Support Services	**2,179**	**2,060**	**1,949**	**1,835**
Total Ongoing Operations	[redacted]			
Darlington Refurbishment	**240**	**258**	**268**	**217**
Total OPG	[redacted]			

*Restated to reflect organizational changes and budget transfers as of June 1, 2013

2014-2016 Total OM&A Guidelines*

$ millions	Budget**	Guideline		
	2013	2014	2015	2016
Nuclear Operations (Excl. Darl Refurb and New Build)	1,432	1,397	1,464	1,481
Nuclear Projects (Excl. Darlington Refurbishment)	123	130	127	121
Hydro-Thermal Operations	[redacted]			
CO&E	43	42	39	40
Total Operations	[redacted]			
Business and Administrative Services	311	306	292	284
Finance - Excluding Insurance	66	64	61	63
Finance - Insurance	28	32	34	37
People & Culture	120	117	112	119
Corporate Office	40	38	43	41
Law	8	7	7	8
Executive Office	16	13	10	10
Total Support Services	**590**	**577**	**560**	**561**
Total Ongoing Operations	[redacted]			
Darlington Refurbishment	**18**	**20**	**18**	**150**
Nuclear New Build	**39**	**10**	**10**	**-**
Total OPG	[redacted]			

*Excluding centrally-held costs held at the corporate level and costs of goods sold
**Restated to reflect organizational changes and budget transfers as of June 1, 2013

2.1 CAPITAL AND PROJECT OM&A GUIDELINES

In addition to guidelines for headcount and total OM&A, as in prior years, resource guidelines for the 2014-2016 BP include ***capital guidelines*** for all operating Business Units and Support Services groups (BUs)[1]. Starting with the 2014-2016 BP, specific ***guidelines for project OM&A*** for each of Nuclear, HTO and CBD are also being issued. The approved 2014-2016 capital and project OM&A guidelines for each of Nuclear, HTO and CBD were developed by Corporate Strategy and Planning, in consultation with the BUs and with the support of Finance, and are provided below. These guidelines are based on assumptions outlined in section 1. Material developments affecting those assumptions, including those resulting from the release of the LTEP, may necessitate revisions to the guidelines. Any such revision will be undertaken in consultation with the BUs. The guidelines for Darlington Refurbishment are to be treated as preliminary at this time.

The development of capital and project OM&A guidelines as part of this year's business planning process represents a move towards a corporate-wide, enveloped-based allocation process for project resources, which recognizes that OPG must prioritize project spending in a way that allows it to balance the objectives of achieving appropriate financial returns, alignment with corporate priorities, and increasing flexibility to respond to changing conditions.

There are no specific project OM&A guidelines for Business and Administrative Services (BAS) or other Support Services groups (other than CBD) for the 2014-2016 BP.

[1] References to BUs throughout the document include both operating Business Units and Support Services groups

2014-2016 Capital Guidelines

$ millions	Budget*	Guideline		
	2013	2014	2015	2016
Sustaining Capital Expenditures				
Nuclear Operations - Minor Fixed Assets	20	21	22	21
Nuclear Projects - Excluding Fukushima-Related**	150	187	155	188
Nuclear Projects - Fukushima-Related**		43	45	1
Total Nuclear	**170**	**251**	**222**	**210**
Hydroelectric [redacted]	[redacted]			
Sir Adam Beck PGS Reservoir Rehabilitation***	3	-	-	88
Thermal	[redacted]			
Total Hydro-Thermal Operations	[redacted]			
BAS	33	35	25	20
Finance	1	1	1	1
People & Culture	1	1	1	1
Corporate Office - Excluding Corporate Busines Development	-	-	-	-
Law	-	-	-	-
Executive Office	-	-	-	-
Total Support Services	**35**	**37**	**27**	**22**
Total Sustaining Capital	[redacted]			
Generation Development				
Niagara Tunnel	184	-	-	-
[redacted]	[redacted]			
Total Hydro-Thermal Development Projects	[redacted]			
[redacted]				
Ranney Falls	3	3	20	19
Other Hydro Projects - Definition Phase	[redacted]			
[redacted]				
Total Corporate Business Development Projects	[redacted]			
Darlington Refurbishment	**530**	**837**	**632**	**850**
Total Generation Development Capital	[redacted]			
Total OPG	[redacted]			

*Restated to reflect organizational changes and budget transfers as of June 1, 2013
**2013 Budget for Nuclear Projects includes any Fukushima-related expenditures
***2013 Budget w as reflected as part of Corporate Business Development; restated for comparative purposes

2014-2016 Project OM&A Guidelines

$ millions	Budget	Guideline		
	2013	**2014**	**2015**	**2016**
Nuclear Projects (Excl. Pickering Cont'd Operations)	99	100	100	91
Pickering Continued Operations	6	6	-	-
Total Nuclear Projects	**105**	**106**	**100**	**91**
Hydroelectric	[redacted]			
Thermal				
Total Hydro-Thermal Operations	[redacted]			
Hydroelectric Business Development	[redacted]			
[redacted]				
Total Corporate Business Development	[redacted]			
Darlington Refurbishment	**18**	**20**	**18**	**150**
Nuclear New Build	**39**	**10**	**10**	**-**
Total OPG	[redacted]			

3.0 KEY PROCESS CHANGES

In addition to the introduction of project OM&A guidelines, the 2014-2016 business planning process includes several other changes from the 2013-2015 process. Several areas of the instructions have been updated or expanded to provide greater clarity and/or more detailed guidance.

In addition to the process changes discussed below, other changes include:

- More detailed requirements for BU information submissions (section 5.1), and planning accountabilities for revenue and gross margin submissions (section 5.2) and non-BU items (section 5.3)
- Better defined scope of the Finance review and sign-off (section 5.4)
- New requirement for BU Controllers and Director, Accounting to sign-off on the trending of input into the Business Planning System (BPS) (section 5.5)
- New requirement to identify cyber security project requirements to BAS Information Technology contacts (section 5.6.1)
- Planning requirements for BT initiatives (section 5.9)
- Updated environmental planning requirements (section 5.11)
- Discussion of the new planned cost model (section 5.7) and the Finance-led business planning review process (section 5.12), both of which may result in changes for next year's business planning cycle

3.1 PAYROLL BURDEN — CONTACT: ALEX KOGAN

Given the recent approval of the 2013-2105 BP by the OPG Board of Directors and the extent of other work programs impacting the company, this year's business planning process is being simplified by keeping the following unchanged from the 2013-2105 BP:

- payroll burden rate for purposes of the 2014 and 2015 standard labour rates (SLR)
- amount of payroll burden in 2014 and 2015 held at the BU-leader level

The impact of updated pension and other post employment benefits (OPEB) costs and other components of burden for 2014 and 2015 will be budgeted as a centrally-held cost at the corporate level. In 2014, the rate variance account (primary pay) will be charged with actual pay, including updated burden. The amount pre-determined for burden at the BU-leader level for year 2014 in the 2013-2015 BP will be journalized on a monthly basis during 2014 from the rate variance account against the budgeted amount of BU-leader level burden. This will ensure that no variance from budget results in 2014 with respect to the BU-leader level burden.

For 2016, burden rates will be calculated based on updated pension/OPEB and other cost forecasts. Once updated burden rates are available in late July/early August, they will be incorporated into the 2016 SLR and reflected in BPS, and will remain fixed. The guidelines for 2016 will be reviewed accordingly at that time. Using the process introduced for the 2013-2015 business planning cycle, the impact of subsequent changes to 2016 burden (either positive or negative) will be held at the BU-leader level. A corresponding amount will be included in the plan for 2016 for each of the BUs.

As in prior years, costs relating to employee incentive plans will be budgeted as a centrally-held cost at the corporate level.

Further discussion of payroll burden and BPS is found in section 5.5.

3.2 REPORTING SEGMENTS — CONTACT: ALEC CHENG

Changes in OPG's generation portfolio have prompted a reassessment of how operating and financial performance should be reported, internally and externally. The reporting segment structure being implemented effective January 1, 2014 is outlined below. Information submissions by the BUs for the 2014-2016 BP are required on the basis of the new structure.

Regulated – Nuclear Generation

- No change

Regulated – Nuclear Waste Management

- No change

Regulated – Hydroelectric

- All currently regulated hydroelectric stations as well as all currently unregulated, non-contracted hydroelectric stations, which are assumed to be regulated effective January 1, 2014 (see section 1.1)

Contracted Generation Portfolio

[redacted]

Services, Trading, and Other Non-Generation

[redacted]

3.3 INFORMATION REQUIREMENTS FOR HTO FACILITIES — CONTACT: ALEX KOGAN

Where applicable, the detailed planning submissions, with the exception of Support Services groups and Commercial Operations & Environment (CO&E), should provide information for each of the HTO facilities or groupings listed below. This is required in light of the assumed regulation of the currently unregulated hydroelectric facilities and new reporting segments and in order to facilitate consistency between business planning submissions and energy supply agreement revenue calculations. For the purposes of the HTO Business Plan presentation, it is expected that information will be aggregated, as appropriate, consistent with the new segment structure discussed in section 3.2.

The specific HTO facilities/groupings are as follows:

- Niagara Plant Group
- Saunders GS
- Ottawa-St. Lawrence Plant Group – excluding Saunders GS
- [redacted]
- [redacted]
- Central Plant Group – excluding [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- Northeast Plant Group – excluding [redacted]
- [redacted]
- Northwest Plant Group – excluding [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

The submissions should address all applicable information requirements outlined in these instructions for each of the above facilities/groupings. This applies, but is not limited, to the following:

- Non-generation revenues and costs
- Fuel/GRC costs
- Directly attributed plant group/station OM&A
- For hydroelectric facilities, allocated plant group OM&A (including method(s) of allocation)
- Assigned/allocated HTO central office OM&A (inducing method(s) of assignment/allocation)
- Depreciation
- Property taxes
- Capital expenditures
- In-service additions
- Station service charges
- Asset service fees

Support Services groups and CO&E are required to follow the cost allocation process described in section 5.1.2 and will continue to attribute their costs at the ***hydroelectric plant group level*** rather than to the individual hydroelectric facilities.

3.4 CONTRACT REVENUE SUBMISSIONS — CONTACTS: LYNN WIZNIAK/LUCILLE COVELLI

The Commercial Contracts group in CO&E is responsible for managing OPG's generation/capacity contracts. As such, Commercial Contracts is responsible for providing revenue inputs to CO&E – Integrated Revenue Planning for the development of the OPG-wide energy production and revenue plan. [redacted]

[redacted]

3.5 USE OF SHAREPOINT — CONTACT: SANDRA RADCLIFFE

BUs will continue to use BPS for submission of financial and headcount information. Supplementary information, analyses and supporting details will no longer be transmitted by e-mail. BUs will submit this information through the ***Business Planning section of*** the ***Team Sites/Finance SharePoint Portal***. Representatives from each applicable BU have been contacted, and responsibility rights have been developed. Individual BU folders will only be accessible by members of that specific BU, as well as the Business Planning & Reporting (BP&R) team.

BU representatives and/or supporting Finance staff in receipt of these instructions via the SharePoint Portal are asked to forward a copy of the instructions and the detailed business planning schedule to their respective senior management, as required.

4.0 SCHEDULE — CONTACT: SANDRA RADCLIFFE

The following is a high level schedule of the key activities for the 2014-2016 business planning process. A detailed schedule can be found on the Business Planning SharePoint Portal.

MONTH	BUSINESS PLANNING ACTIVITY
June	• Historical labour data submission by People and Culture to BP&R – **June 19** • Completion of labour rate review by BP&R – **July 8**
July - Aug	• Continuing site and BU plan development • Preliminary energy production and revenue plan issued – **July 16** • Roll-out of initial payroll burden rate change (only for 2016 SLR) and review of 2016 guidelines, as required – **August 6** • Submission of final inputs into energy production and revenue plan to CO&E – Integrated Revenue Planning – **August 22**

Sept - Oct	• Initial submissions to BP&PR of BPS input and supplementary information for 2014-2016 – **September 6** • Submission of analyses to BP&PR – **September 9** • Final energy production and revenue plan issued – **September 12** • Finance Review Sign-offs by BU Controllers and Director, Accounting submitted to BP&PR – **September 16** • CEO/CFO reviews for all BUs – **September 18 to September 24** • Revised BU submissions and updated Finance Review Sign-offs provided to BP&RP no later than **September 30** (if required) • Submission of final contract revenue inputs to Commercial Contracts – **September 30**
October	• Update planned BU-leader level costs for 2016 payroll burden changes – **October 4** (if required) • Finalization of corporate level information including variance & deferral accounts, interest, and income taxes
November	• BUs finalize 2014 monthly and 2015/2016 monthly/quarterly trending and related BPS input (OM&A, capital, fuel, non- generation revenues, provision expenditures, headcount) – **November 6** • Approval of the 2014-2016 BP by the OPG Board of Directors – **November 15**
December	• Finalization of cost allocations and loading of budgets into reporting systems • Issuance and acknowledgement of budget letters • Conversion of planning information to Shareholder's fiscal basis

Note: *Throughout the business planning process, draft planning information will be shared, and review meetings will be held, with OPG's Shareholder.*

5.0 BUSINESS PLANNING AND BUDGETING INSTRUCTIONS

5.1 BU INFORMATION SUBMISSIONS — CONTACT: SANDRA RADCLIFFE

Business planning submissions are required from each BU for each of the three years of the 2014-2016 period in the following form:

- Quantitative resource and financial information to be submitted through BPS by ***September 6, 2013***, with trending finalized by ***November 6, 2013*** (see section 5.5)
- Supplementary quantitative financial information and supporting analyses to be submitted through the Business Planning SharePoint Portal (see section 3.5) in the form of Excel spreadsheets and/or Word or PowerPoint documents by ***September 6, 2013***; year-over-year and plan-to-guideline analyses to be submitted by ***September 9, 2013***
- Business Plan PowerPoint presentation to be made to CEO/CFO (see section 5.1.1)

Resource and financial information by work program and resource type/cost element is the level of detail required for the business planning submissions. Preliminary summarized quarterly detail for each of the three years 2014-2106, with an emphasis on realistic forecasts for Q1 of each year (for Shareholder's fiscal year-end purposes), is sufficient for the purposes of submissions due by ***September 6, 2013***. The trending of submissions in BPS, including monthly detail for budget year 2014 and quarterly detail thereafter, must be finalized by ***November 6, 2013*** (see section 5.5).

Information submissions for all three years of the plan should be based on the existing organizational structure as of June 1, 2013 (unless specifically agreed with BP&PR).

The specific resource and financial information requirements include:

- OM&A expenses reconciled to total OM&A guidelines outlined in section 2.0, with project OM&A reconciled to project OM&A guidelines (for applicable groups), as outlined in section 2.1
    - If the submission exceeds guidelines, reconciliations should identify specific sources of variance from guidelines and underlying drivers, including reasons for the variance not having been mitigated

  - Nuclear OM&A in support of Continued Operations at Pickering through to the end of 2014 should be identified separately (***for each of base, project and outage categories***)
  - OM&A transferred to Darlington Refurbishment, Nuclear New Build and [redacted] should be identified separately (refer to section 5.7)
- Capital expenditures (including intangible assets and capital spares) balanced to project listings, as directed in section 5.8, and expenditures on minor fixed assets, together reconciled to capital guidelines for applicable groups, as outlined in section 2.1. Reconciliations should identify specific reasons for variance and underlying drivers. Expenditures on capital spares should continue to be identified and input into BPS as a separate classification.
- Fuel expense (including nuclear fuel, GRC and [redacted]) must be submitted to BP&RP as well as Integrated Revenue Planning as part of the inputs into the energy production and revenue plan (refer to the detailed business planning schedule for submission dates to Integrated Revenue Planning)
- Non-generation revenues and costs of goods sold, including [redacted] and commercial sales contracts (refer to section 5.2 for revenue and margin planning accountabilities)
- Staff details, including headcount (by representation), reconciled to the guidelines outlined in section 2.0, and FTE funding
  - If the submission exceeds guidelines, reconciliations should identify specific sources of variance from guidelines and underlying drivers
- Nuclear decommissioning and waste management provision expenditures, including station decommissioning and staff providing dedicated support services to the Nuclear Waste Management Division (e.g., security), as discussed in section 5.1.3
- Other provision expenditures, including drawdowns of environmental or First Nation provisions and the non-nuclear station decommissioning provision
- New provisions that are expected to be set up during the planning period and any related drawdowns

The following supplementary information is to be submitted in spreadsheets or other documents:

- Capitalized interest, asset retirements/write-offs and in-service addition forecasts consistent with capital project plan details submitted in BPS and project listings, including capital spares, intangible assets and minor fixed assets. If bottom-line adjustments have been used to balance capital submissions, these must be factored into interest capitalization and in-service addition forecasts. Quarterly details for these items are required for all three years. ***Note:*** Monthly detail is required where a single in-service addition or asset retirements/write-off is at least $50 M, as well as for all Darlington Refurbishment items.
  - The 2014-2016 assumption for the non-project specific interest capitalization rate is 5.00%
- Submission of planning information for cash inflows from the nuclear segregated funds, consistent with the planned drawdowns of the nuclear decommissioning and waste management provision, will be coordinated by BP&R – Nuclear Liabilities. Assumptions for rates of return for the segregated funds will be established and provided by BP&PR in conjunction with Treasury.
- Working capital items (annual detail is sufficient initially):
  - Fuel inventory
  - Material and supplies inventory
- Cost segmentation – BUs must attribute all submitted costs and expenditures based on the segment reporting structure outlined in section 3.2. Information for the HTO facilities should be provided in the level of detail outlined in section 3.3 (with the exception of Support Services groups and CO&E; see section 5.1.2). Where possible, nuclear provision expenditures should be attributed directly to Pickering Units 1 & 4 and Pickering Units 5-8.
- [redacted]
- Year-over-year analyses of changes in resources (e.g., OM&A, capital, fuel, non-generation revenues and cost of goods sold, provision expenditures) at the BU-level (Nuclear Operations, Nuclear Projects, HTO, CO&E, each Support Services group) are required. ***Year-over-year analysis has taken on increasing importance and submissions are expected to be comprehensive.*** While no specific format is prescribed in recognition of differences across the BUs, analyses should be provided in the form of a year-over-year continuity (roll) in a level of detail that is sufficient to fully explain the material factors contributing to the change. Programmatic changes should be separated from rate changes.

Where material, submissions should specifically identify impacts driven by outage profiles, non-standard projects, or non-recurring or infrequent events.

Any changes to planning submissions subsequent to September 6, 2013 must be reported to, and confirmed with, BP&PR and, by November 6, 2013, reflected in BPS. This includes any adjustments or corrections, as well as changes resulting from the CEO/CFO review process.

5.1.1 Business Plan Presentations — *Contact: Sandra Radcliffe*

Similar to previous years, the Business Plan presentations for BUs should identify objectives, performance targets, resources, key initiatives and assumptions, risks and mitigation strategies. Program write-ups, plan-over-plan comparisons to the approved 2013-2015 BP, plan-to-guideline reconciliations and year-over-year differences, with analyses of changes in resources and programs, should be included. A draft of the presentation must be provided to BP&PR at least ***three (3) business days*** in advance of the schedule CEO/CFO review meeting. A separate presentation summarizing the final approved energy production plan, including key assumptions, dependencies, risks and mitigation strategies, must be submitted by Integrated Revenue Planning to BP&PR by ***October 4, 2013***.

5.1.2 Cost Allocations for Support Services and CO&E — *Contacts: Paul Chabot/Michelle Girard*

Support Services groups and CO&E are required to assign/allocate all submitted costs as outlined in sections 3.2 and 3.3, with the exception that, in assigning/allocating costs to hydroelectric facilities, Support Services and CO&E should only attribute costs to the hydroelectric plant group level (i.e., Niagara PG, Saunders GS, Ottawa-St. Lawrence PG excl. Saunders GS, Central Hydro PG, Northeast PG, Northwest PG). Support Services groups and CO&E are expected to provide their rationale for management estimates made for the purposes of cost assignment/allocations. As in prior years, a template for this information will be provided by, and must be submitted to, Support Services Controllership. The submission due date is ***September 12, 2013***.

5.1.3 Nuclear Provision Expenditures — *Contacts: Banh Tran/Alex Kogan*

Planning for nuclear decommissioning and waste management provision expenditures requires the same rigour and change management process as OM&A and capital expenditures. Similar to OM&A, provision programs are classified as either base or project. Each provision program is to have a designated executive sponsor responsible for scope, life-to-date and annual expenditures, and approval of budget with executing organization.

Business planning for nuclear provision expenditures must follow the schedule and process set out in these instructions for BPS loading, analysis submission, and presentation. ***Therefore, any changes to planning submissions for provision expenditures after September 6, 2013 must be reported to, and confirmed with, BP&PR and, by November 6, 2013, input into BPS.*** These changes also must be reported to BP&R – Nuclear Liabilities.

5.2 REVENUE AND GROSS MARGIN SUBMISSIONS — CONTACTS: SANDRA RADCLIFFE/BILL WILBUR

The accountabilities for revenue and gross margin information submissions to BP&PR are outlined below. While BP&PR may initially receive some of this information from groups other those identified below, it is ultimately the responsibility of the identified groups to make the official submissions in accordance with the detailed business planning schedule. Any additional sources of revenue expected during the planning period should be identified to BP&PR by the group responsible for managing the revenue source.

Unless otherwise specifically noted in the business planning schedule, revenue and gross margin submissions are due at the same time as those outlined in section 5.1, i.e., by ***September 6, 2013***. A separate set of dates is set out in the schedule for the development of the energy production and revenue plan.

****For items marked with an asterisk in the table below, the identified groups are responsible for inputting the planning submission into BPS, including monthly trending for the budget year 2014.***

REVENUE SOURCE	BUSINESS PLANNING ACCOUNTABILITY
Generation/Capacity Revenue (incl. new projects) • [redacted] • [redacted] • Ancillary revenues	CO&E – Integrated Revenue Planning *(as part of Energy Production and Revenue Plan)*
[redacted]	[redacted]
Nuclear Non-generation Revenue* • Isotope Sales • Heavy Water / Detritiation sales and services • Bruce Lease Rent (incl. changes in fair value of the embedded derivative and rent rebate payments) and ILW/LLW Services	CO&E – Commercial Contracts *(Revenue)* Nuclear *(Cost of Goods Sold)*
Nuclear Non-generation Revenue* • Engineering Services • Investment Recovery	Nuclear
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
HTO Non-generation Revenue*	HTO
Training and Other Revenue*	People and Culture

5.3 OTHER INFORMATION SUBMISSIONS — CONTACTS: ALEX KOGAN/SANDRA RADCLIFFE

The accountabilities for certain other information submissions for the 2014-2016 BP are outlined below. While BP&PR may initially receive some of the information from groups other than those identified below, it is ultimately the responsibility of the identified groups to make the official submissions in accordance with the business planning schedule. Key assumptions and dependencies should be identified as part of the information submissions.

ITEM	BUSINESS PLANNING ACCOUNTABILITY
Pension and OPEB Costs – final update by ***September 26, 2013***	Finance – BP&R – Actuarial
Deferral and Variance Accounts – final update by ***September 27, 2013***	Finance – BP&R – Regulatory Finance
Depreciation /Amortization – ***September 6, 2013*** ○ Based on current net book values of fixed/ intangible assets and station end-of-life dates/ average asset class service lives expected to be in effect during the planning period.	Finance – Shared Financial Services – Accounting

○ Planned changes in asset class/station lives, taking into account changes expected through from the Depreciation Review Committee process, should be noted	
Property Tax (separately showing amount to be charged against nuclear decommissioning provision) – ***September 6, 2013***	Finance – Investment Planning – Property Tax
Accretion on Nuclear Waste Obligations and Earnings on Nuclear Segregated Funds – ***September 26, 2013***	Finance – BP&R – Nuclear Liabilities (*requirements for inputs to be provided to BP&R – Nuclear Liabilities by other groups are outlined in the detailed business planning schedule)*
Employee incentive plans (centrally held cost) – ***September 6, 2013***	People & Culture – Total Rewards & Solutions Centre
Vacation accrual and fiscal calendar adjustment (centrally-held costs) – ***September 6, 2013***	Finance – Shared Financial Services – Accounting
Asset Service Fees (corporate and hydroelectric) – ***September 6, 2013***	Finance – Support Services Controllership
[redacted]; Interest Expense	Finance – BP&PR *(for interest, reflecting inputs from Treasury and capitalized interest from BUs)*
Income Tax	Finance – Income Tax

5.4 FINANCE REVIEW AND SIGN-OFF — CONTACT: ALEX KOGAN

Senior Finance staff from the following groups will complete a financial review and sign-off for the business planning submissions for the groups that they support/represent and submit the results/ confirmation to BP&PR by the dates indicated.

- All BU Controllers by ***September 16, 2013*** (**note:** CO&E – Commercial Contracts' non-generation revenue and margin submissions to BP&PR, as well as the nuclear inventory obsolescence assumptions, will be included in the review and sign-off by the Support Services Controller)
- Director, Accounting by ***September 16, 2013*** – [redacted], depreciation & amortization (excluding amortization of deferral and variance accounts) and centrally-held costs per section 5.3, as well as inputs to BP&R – NL for nuclear waste obligations and segregated funds per the detailed business planning schedule
- Senior Manager, Nuclear Liabilities by ***September 26, 2013*** – nuclear decommissioning and waste management obligations based on inputs provided
- Director, External Reporting & Policy by ***September 30, 2013*** – pension and OPEB assumptions, calculations and accounting treatment
- Manager, Regulatory Finance by ***September 30, 2013*** – deferral and variance account assumptions, calculations and accounting treatment
- Director, Taxation by ***October 31, 2013*** – income tax
- Senior Manager, Treasury Operations by ***October 31, 2013*** – treasury inputs

The sign-off will confirm that the Finance staff have reviewed the planning submissions and are, at a minimum, in agreement with the following in respect of the overall submission:

- Appropriateness and consistency of financial/economic assumptions
- Compliance of submissions with US Generally Accepted Accounting Principles (GAAP), including, where appropriate, consistency of application of these principles across periods and transactions
- Completeness and accuracy of the financial submissions on the basis of known operational assumptions

- Where applicable, consistency of BPS submissions with information on work programs, cost and staffing levels reflected in the CEO/CFO review meeting presentation (updated, as necessary, based on the outcome of the meetings)
- Where applicable, basis of investment decisions identified in the plan
- Where applicable, compliance of financial/economic assumptions and calculations with contractual, legal, regulatory or other requirements, and OPG governance
- Compliance with these business planning instructions

BP&R will issue a checklist or similar document aid to facilitate the Finance sign-off and review process. However, as in prior years, the sign-off can also take the form of a memo or e-mail addressed to Vice-President, Finance, Chief Controller & CAO and Vice-President, Business Planning & Reporting, provided that it covers the above-noted items, as well as provides assurance over the following, where applicable:

- All asset removal costs, in-service additions, and asset retirements have been identified in the appropriate period and have been correctly classified in accordance with US GAAP as applied by OPG
- Interest capitalized on construction and development in progress has been calculated using the applicable rate(s) in accordance with US GAAP as applied by OPG
- All costs have been appropriately classified as capital, OM&A or provision expenditures in the appropriate period in accordance with US GAAP as applied by OPG
- All contractual milestone accruals have been budgeted in the appropriate period
- Valuation of materials and supplies inventory and related obsolescence charges are appropriate
- Valuation and depreciation/amortization of fixed and intangible assets (based on station/asset class services lives) are appropriate in accordance with US GAAP as applied by OPG
- Assumptions and valuations for provisions other than for nuclear decommissioning and waste management (e.g., First Nations, environmental, [redacted], etc.) based on measurability and probability of occurrence are in accordance with US GAAP as applied by OPG
- Assumptions underlying the obligations for nuclear decommissioning and waste management are appropriate, and the obligations are fairly stated in accordance with US GAAP as applied by OPG
- All regulatory asset and liability balances are appropriately stated in accordance with US GAAP as applied by OPG
- All derivative financial instruments have been identified and appropriately recognized/valued in accordance with US GAAP and their application by OPG
- Inputs into contract generation/capacity revenue calculations are appropriate and consistent with cost and other planning submissions to BP&PR
- All material accounting implications of any policy changes have been identified
- Income and other tax calculations have been appropriately performed
- Other items, taking into account the risk of error, materiality and sensitivity of the item, extent of judgement required, the nature of the item (recurring vs. non-recurring/unusual), and the complexity of accounting

5.5 INSTRUCTIONS FOR USE OF BPS — CONTACT: KAREN MOONEY

There will be three versions of BPS utilized for the three years of the 2014-2106 BP:

- **W01** will contain the 2014 and 2015 SLR, including burden, by job family as used in the 2013-2015 Business Plan. All BUs will use BPS version W01 for planning.
- **W02** will contain new SLR applied to the 2014-2106 BP submissions for the purposes of isolating SLR change impacts. The new SLR will reflect updated economic assumptions and actual 2013 experience. As discussed in section 3.1, ***burden rates for 2014 and 2015 will not change throughout the entire planning process.*** The updated SLR should be available in BPS by end of June, and a labour rate review will be completed by BP&R – Management Reporting & Forecasting by ***July 8, 2013***.
- **W03** will be used to validate the distribution of pension/OPEB costs to the BUs through changes to the burden rate for 2016. The roll-out of initial estimate of payroll burden rate changes for 2016 is targeted for ***August 6, 2013***. (Additional time is expected to be required this year for this roll out due to a requirement to perform a detailed update of all data and assumptions used in the calculation of the pension and OPEB liabilities for accounting purposes.) As discussed in section 3.1, ***changes in***

burden for 2014 and 2015 will be held as a centrally-held cost at the corporate level (not passed down to the BUs). Only 2016 burden rates will be updated in BPS, by August 6, 2013, and incorporated into the BU submissions.

Submissions for the 2014-2016 BP contained in W01 can be copied over to versions W02 or W03 at the request of the respective BU, in order to determine the impacts from SLR changes or changes in the 2016 burden rate. At least two business days must be allowed for processing. All SLR contained in W02 and W03 will be copied over to W01 in August at the request of the respective BU, but no later than ***August 30, 2013***.

Resource submissions and preliminary Business Plans are to be completed in W01 by ***September 6, 2013***. The details required in order to consolidate information for the 2014-2016 BP are outlined below. BPS will be locked for two business days following the submission day to allow for the consolidation of data by BP&R.

- Work program and project information should be trended in BPS for all three years, initially on a quarterly basis
- BUs must ensure that assumptions for hiring lags, vacancy management (e.g., filling vacancies in existence at the beginning of the planning period) and project initiation reflect actual experience and realistic expectations. Support for the assumptions in this area (e.g., historical trends) should be clearly documented.
- Total labour requirements must be balanced to the total labour supply in the Labour Planning Module of BPS.
- Headcount trending must be input into BPS. ***BUs must ensure that realistic assumptions are used for headcount trending, particularly as headcount has become a key metric in light of Business Transformation.*** There continues to be an increasing focus on budget-to-actual comparisons for headcount information during the year.

Final trending information is required on a monthly basis for budget year 2014 and, at a minimum, on a quarterly basis thereafter. By end of day on ***November 6, 2013***, all trending and adjustments must be completed in W01 on this basis, and BUs will be locked out of BPS for the 2014-2106 business planning process. At that point, the trending by the BUs will be considered final and, for the 2014 budget year, ready for upload to SAP and reporting systems. ***By November 6, 2013***, ***BU Controllers will be required to provide a sign-off to BP&PR confirming that the trended BPS input (BU OM&A, capital, fuel, provisions, non-generation margin as per section 5.2, and headcount) is complete and accurate, based on reasonable assumptions, and agrees to the CEO-approved resource levels.*** For greater clarity, this sign-off is intended to be specific to the trending of the previously submitted information and, therefore, is additional to the requirements of the Finance review and sign-off discussed in section 5.4.

Additionally, the following input will be reflected in BPS:

- BP&R – Management Reporting & Forecasting is responsible for developing the BPS trending of labour rate variances, to be held at the corporate level
- BP&PR will develop trending for accretion expense and earnings on nuclear segregated funds, applicable centrally-held costs and, based on in-service information provided by the BUs, for depreciation & amortization expense
- Trended BPS input for generation revenue will be provided by Integrated Revenue Planning by ***November 18, 2013***, incorporating regulated revenue assumptions from BP&PR as required, and will be ***signed-off by Director, Accounting***
- Trended BPS input for deferral and variance accounts will be provided and ***signed-off by Finance – BP&R – Regulatory Finance*** by ***November 18, 2013***

Throughout the process, Support Services Controllership and BP&R will work with Support Services groups and other groups requiring assistance in incorporating their input to BPS.

5.6 BUDGETING FOR SERVICE PROVIDERS — CONTACTS: LUBNA LADAK/BOSCO YUAN

The BUs should continue to work closely with BAS service providers such as Information Technology (IT), Real Estate & Services and Supply Chain to jointly agree on service requirements and associated costs. The costs should be adequately reflected in the service provider's planning submission. All OM&A, provision and capital expenditures, including those for minor fixed assets, will be held by the service providers on behalf of the BUs. It should be ensured that there is no duplication in budgets between the BUs and service providers. Service Level Agreements, as defined through Business Transformation, are a useful tool for accomplishing this objective.

5.6.1 Information Technology Requirements

IT requirements should be identified to the IT support groups within BAS. The BAS Business Plan will include resources for all business-related IT needs, IT projects, and IT components of business initiatives. These initiatives are only exclusive to Darlington Refurbishment, Nuclear New Build and [redacted] (see section 5.8).

The following IT expenditures should be incorporated into each BU's Business Plan, rather than in the BAS Business Plan, as they are directly tied to station process control, which is not available through existing IT commodity contracts:

- Process control hardware and software in Nuclear and HTO
- Engineering tools (hardware) and new software in Nuclear and HTO (annual maintenance for most existing software is covered by BAS)

Where a BU is asking IT to assume budget accountability for existing items (e.g., annual maintenance contracts), a list of the items and their related costs should be provided to IT for inclusion in the BAS plan. If there is uncertainty as to whether or not a particular contract is identified in the BAS plan, one of the contacts listed below should be consulted.

For the 2014-2016 BP, IT will budget for all cyber security project OM&A and capital expenditures, including those related to process control and real time systems. BUs should identify their cyber security project requirements to their IT contacts below.

The Enterprise Systems Consolidation Project (ESCP), formerly known as the Information Management Transformation or IMT project, is now in the execution phase. In order to ensure its success, the project continues to require active leadership involvement, support, cross-organizational collaboration, and strong change management. For the 2014-2016 BP, BAS, as the project owner of ESCP, will only budget for directly attributable costs associated with the User Acceptance Testing, including IT and non-IT resources. BUs are required to include all other resourcing costs relating to the execution phase of the project in their respective plans.

Currently, the IT project portfolio is fully allocated, as projects are in the process of being locked down over the planning period per the previous business plan and the incremental Business Transformation Strategy approved initiatives.

To confirm whether specific items are included in the BAS plan, please contact your IT contacts as shown below:

- Enterprise Systems Consolidation Project – Mike Borsch (400-8274 at Head Office)
- Business Transformation Strategy – Mike Borsch (400-8274 at Head Office)
- Nuclear – Warren Hobbs (702-5131 at Pickering)
- HTO and Support Services – Amir Shemranifar (400-6981 at Head Office)
- CO&E – Howard Mintz (400-1826 at Head Office)
- Cyber Security – Glenn Dempster (400-3555 at Head Office)

5.6.2 Strategic Sourcing Requirements

Effective January 1, 2014, the Nuclear business unit will be responsible for procuring non-plant materials and supplies directly through the self-serve ARIBA network. These items were previously stored as inventory by the Nuclear Supply Chain (NSC) and only charged to expense by the Nuclear business unit when issued. Going forward, these items will be expensed when purchased and, therefore, the Nuclear business unit should incorporate these expenditures into its 2014-2016 Business Plan. For specific details on these new requirements, please contact Dave Hudson, Director, Warehouse & Logistics (703-7485 at Darlington).

Hydro-Thermal/Corporate Supply Chain has been working with the BUs on an inventory draw down plan related to [redacted] and continues to administer, negotiate, and execute contracts in support of [redacted], [redacted], and other Hydroelectric development projects.

In the NSC, cross-functional (plant-focused) performance measures adopted in 2011 will continue to drive the required behaviours and results during the planning period. NSC will work with Nuclear Fleet Operations, Maintenance, and Engineering to further refine and align performance measures across the groups. Key strategies underlying the 2014-2016 BP are as follows:

- **Parts Availability –** Managing and organizing the acquisition and distribution activities in support of on-line and outage improvement strategy, work order readiness, vendor quality and supplier performance management, improving equipment reliability, and reducing replenishment of material stocked out

- **Materials and Supplies Management** – Working collaboratively with the stations and Nuclear support organizations to improve material availability via the work management, on-line and outage planning, and project management processes

- **Pickering End-of-Life** – A comprehensive demand plan strategy will be required to address the closure of the Pickering units by the end of the decade. Initiatives may include disposal of dead stock, increase in consumption, adjustments to the preventive maintenance program, and adoption of a “repair strategy”, as opposed to a “replace strategy”. NSC and Nuclear are to identify and plan for all provision funding necessary to support safe storage and decommissioning of the Pickering units.

5.6.3 Real Estate & Services Requirements

Real Estate & Services requirements (e.g., new leases, lease renewals, facility enhancements/modifications, furniture, staff moves, surveys, imagery, printing, graphics, etc.) for each BU (including Darlington Refurbishment and Nuclear New Build) are to be clearly identified to Real Estate & Services for consideration and inclusion in their planned work programs. Real Estate & Services will consolidate all facility costs in accordance with an overall leasing strategy and will identify any costs to be charged directly to the BUs.

It is emphasized that under the OPG Organizational Authority Register, ***only*** Real Estate & Services has requisitioning authority for the acquisition, management, and disposal of real estate rights and interests, and related transactions.

Real Estate & Services has identified the following contacts by service area:

- Real Estate Services – Ron Murphy (400-7201 at Head Office)
- Facility & Project Services – Don Seedman (400-3289 at Head Office)
- Business Infrastructure Services – Keith Skrepnek (905-576-6959 x3384)
- Fleet Services – Joe Werb (416-231-4111 x6048 at Kipling)

5.7 WORK FOR OTHERS — CONTACTS: SANDRA RADCLIFFE/CRAIG SMALLMAN

The 2014-2016 BP will be prepared on the basis of the current cost model for all years of the plan. Under the current cost model, organizations are to budget for all of the resources they control. This will result in organizations holding budgets that they will transfer if the resources are provided by a different group/BU.

During the planning period, Support Services groups may be requested to provide dedicated services to major projects. Vice-President, Finance, Chief Controller & CAO will determine which major projects will be eligible for cost transfers prior to business plan submissions. Darlington Refurbishment and Nuclear New Build are already recognized as major projects and, therefore, are eligible for cost transfers, provided that the receiving organizations have provided their approval.

Specifically, non-Nuclear planning submissions should include cost transfers for resources in support of Darlington Refurbishment and Nuclear New Build only to the extent that the funding for such resources has been explicitly approved, ***prior to making the submission***, by SVP, Nuclear Refurbishment for Darlington Refurbishment and SVP, Corporate Business Development & CRO for Nuclear New Build. Only incremental efforts directly associated with Darlington Refurbishment and Nuclear New Build will be considered for cost transfers. Services provided by Support Services groups as part of the normal course of business in a centre-led organization should be included in their ongoing OM&A work programs. There will be no requirements for cost transfers between groups in Nuclear Operations or Nuclear Projects.

[redacted]

For purposes of capitalization, costs should be classified as directly attributable to the eligible projects in accordance with US GAAP as applied by OPG.

Headcount for the dedicated support services provided to major projects will remain with the support group. For presentation and analytical purposes, ***both originating and receiving groups' planning submissions must show the gross and net costs associated with these transfers***. This will ensure that there is no duplication in budgets between the project and service providers.

Under the planned new cost model targeted for implementation effective January 1, 2015, service providers will hold budgets for intracompany services and report the actual costs of all resources belonging to their organization. There will be no cost transfers. In preparation for the transition to the new model, as part of the current business planning cycle, service receivers are required to identify and estimate the annual resources (e.g., internal machine shops, diving services) that they expect to be supplied by other OPG sites during the 2014-2016 period. The identification and communication of this information is expected as part of the planning process in a centre-led matrix organization that OPG has implemented. Under the planned new cost model, a formal resource commitment mechanism and standard template will be implemented to facilitate communication between, and planning by, budget holders.

5.8 CAPITAL, OM&A AND PROVISION-FUNDED PROJECTS — CONTACT: DOROTHY LAU BARTON

This section specifies the requirements for submission of the 2014-2016 BP capital, OM&A and provision-funded project portfolio listings and supporting Planning Business Cases (BCSs). BUs are requested to provide their project information by ***September 6, 2013 to Jack Fong*** in Finance – Investment Planning.

Section 5.8.1 specifies the listing requirements for the project portfolios. Section 5.8.2 provides the criteria for projects requiring Planning BCSs and the information requirements for Planning BCSs. Questions on these requirements should be directed to Dorothy Lau Barton (400-4580 at Head Office) or Jack Fong (400-4655 at Head Office).

5.8.1 Prioritized Project Lists

BUs are required to identify all capital, OM&A and provision-funded projects having cash flows within the business planning period. The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives, as well as efficient alignment with business unit strategies, facility Life Cycle Plans (as applicable), Condition Assessments and Shareholder expectations.

The listing format and information requirements have not changed from the previous year and are provided in the ***Project Listing Template***, available in the ***Investment Planning Toolkit*** section of the Finance SharePoint site. Definitions and explanations for the various fields in the template are provided in the ***Guidelines*** worksheet of the template. To facilitate corporate review, consolidation and reporting, it is essential that BUs provide all information in the format specified in the listing template. It is also requested that each BU provide a description of their prioritization process.

To assess needs for skilled craftspeople from the construction trades, the "trades resource program" category in the Project Listing Template should be completed. This categorization is being used to identify the type and number of skilled craftspeople and total project costs, by year, from the various construction trades. For additional information please refer to the Guidelines worksheet. For questions regarding the use of this information, please contact Laurie Gawel in People and Culture – Performance & Program Analysis (400-2499 at Head Office).

5.8.2 Planning Business Cases

BUs are required to submit Planning BCSs, or an equivalent document, for projects listed in their portfolio that are ***not fully released*** and meet the following criteria:

- Projects planned for release in 2014 with cash flow greater than $1 M in 2014
- Projects planned for release in 2014, 2015, or 2016 with a total project cost greater than $5 M

For the purpose of these instructions, ***not fully released*** projects include:
- Projects with no previous releases
- Projects with developmental (preliminary) and/or partial releases where the project has not been fully committed
- Previously released projects that are forecasting significant changes in scope/cost and are planned/expected to have a superseding release

The information requirements for Planning BCSs are specified in the ***Planning BCS Template***. Additional information and explanation are provided in ***Developing and Documenting BCS (OPG-STD-0076)***. Both of these documents are available in the Investment Planning Toolkit on the Finance SharePoint site. The above requirements also apply to projects in support of non-generation business opportunities.

While the Planning BCS Template sets out the information requirements, BUs will often have existing documents that meet the specified information requirements. When such documents (e.g., Type 1, 2 or 3 BCSs) are available and up-to-date, particularly with respect to cash flows, they can be submitted in place of the Planning BCS.

All Planning BCSs should be reviewed and signed-off by the appropriate project sponsor (e.g., Asset Manager, Engineering Director, etc.) and the local Controller.

5.8.3 BCS Preparation Assistance

For assistance with BCS preparation, please contact your local Controller or centre-led business group. In addition, BCS training sessions can be arranged. For registration, please contact Silvester Wong of Investment Planning (400-3842 at Head Office).

5.9 BUSINESS TRANSFORMATION INITIATIVES — CONTACT: NICOLLE BUTCHER

As discussed in section 1.0, achievement of cost reductions and efficiencies through Business Transformation is a key initiative in pursuing OPG's strategic objectives. As such, the BUs should reflect in their Business Plans the continued implementation and management of the applicable BT initiatives. There will be no corporately-held funding in the 2014-2016 BP for the implementation and management of the initiatives.

5.10 BUSINESS UNIT RISK SELF-ASSESSMENT — CONTACT: TOM LUMLEY

As part of developing realistic, comprehensive and transparent Business Plans, risks should be identified, assessed and incorporated, along with risk treatment plans, in each Business Plan. The goal of the Business Unit Risk Self-Assessment (BURSA) is to identify, assess, and document risks that could impact the achievement of BU objectives over the 2014-2016 business planning period. Risks that are long-term in nature should also be discussed with the Enterprise Risk Management (ERM) team.

As BURSA is also a part of the continuous ERM reporting process, on a quarterly basis, an update of existing risks, along with the identification of new risks, will be required. Therefore, in addition to being reported in the Business Plans, these risks form the basis for quarterly risk reporting to the committees of the OPG Board of Directors.

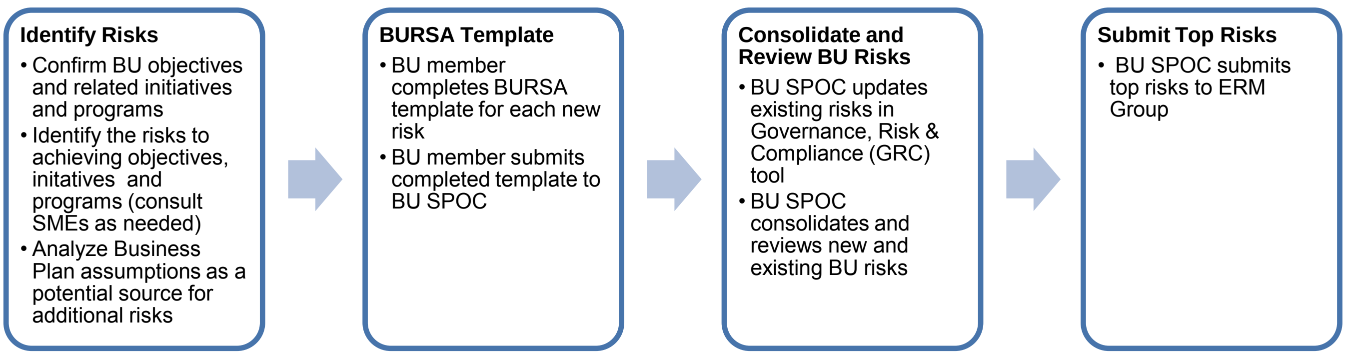
The following are the key BURSA submission dates:

- August 20, 2013 – BURSA kick-off e-mail
- September 3-13, 2013 – ERM group meetings with BU Single Point of Contacts (SPOC)
- September 20, 2013 – BU SPOCs submit BURSA to ERM group

Further instructions, tools and templates will be distributed by the ERM group to all BU SPOCs by e-mail.

The BURSA Process

The main steps for the BUs to complete the BURSA are shown below:



The ERM group consolidates and reviews all individual BU risk submissions.

OPG senior executives will validate the list of prioritized risks to determine the risks to be reported to the OPG Board of Directors. This may result in updates to the GRC tool.

Risks Impacting Business Continuity and Emergency Management

As a result of Business Transformation, Business Continuity Programming is now part of ERM. This amalgamation has created an opportunity to streamline risk processes and to simplify the ongoing maintenance of the business continuity Business Impact Assessments (BIAs). In 2014, there will be a requirement to migrate all risks currently identified in the BIAs, consolidating these risks with the existing risks in the BU risk registers, as well as noting any emergency response programs for residual risks. Risk identification should also be expanded at that time to ensure that all of the 39 Emergency Management Ontario hazards have been considered. Details related to completing this task will be provided in Q4 2013. Business Units should make plans to complete this exercise in 2014.

Main Outputs from the BURSA process

- **BURSA Template** – Any new risks that have been identified should be documented in the BURSA template (to be provided).

- **GRC Update** – Any existing enterprise risks should be updated, similar to the quarterly ERM update process, within the GRC tool.

- **Business Plan Presentation –** The most significant risks stemming from the BURSA process should be captured in the Business Plans. A sample presentation template for submitting the BURSA information is available in the ***ERM section*** of the ***Development, Law, Regulation & Risk SharePoint site***.

5.11 CORPORATE SAFETY — CONTACT: JASON FITZSIMMONS

With safety as a core value, OPG is committed to safety excellence, sustaining a strong safety culture and continuous improvement in pursuing the goal of zero injuries. The BUs are expected to program accordingly. At this time, there are no specific requirements for planning submissions in the area of corporate safety.

5.12 FIRST NATIONS INITIATIVES — CONTACT: JOE HEIL

OPG recognizes the importance of strengthening relationships with the Aboriginal Peoples in Ontario, as is reflected in the ***First Nations and Métis Relations Policy (OPG-POL-0027)*** and supporting Standard and Manual. All operating BUs and other line organizations that have regular contact with Aboriginal communities are required to develop programs in support of this Policy and include relevant resource requirements in their Business Plans. For further guidance on program requirements, please refer to the above Policy, Standard and Manual found under *Governing Documents* on the ***Nuclear Support SharePoint site***.

5.13 ENVIRONMENTAL PLANNING REQUIREMENTS — CONTACT: ROB LYNG

The environmental component of OPG's business plan is centred on implementing programs to meet the requirements of the ***Environmental Policy (OPG-POL-0021)***, which is found on the ***Environment SharePoint site***, including the following:

- Maintaining a single OPG Environmental Management System (EMS) certified to ISO 14001 standard
- Effectively managing of OPG's Significant Environmental Aspects (SEA)
- Considering changes in environmental legislation

Maintaining a single OPG Environmental Management System

OPG will maintain a single OPG EMS. BUs should not budget for maintenance of a local ISO 14001 environmental management system. Operating BUs and functions should budget for maintenance of those components of the management system that are within their accountabilities, e.g., Operational Control.

Significant Environmental Aspects

BUs are asked to review OPG EMS Program Summary documents on the Environment SharePoint site *(Governing and Supporting Documents* section), for each of the OPG's SEA as described in the table below. BUs should budget to meet these program requirements. In order to ensure good management of environmental aspects, including timely receipt of any required environmental approvals, BUs are asked to identify the following in their Business Plans:

- Any new or revised programs, projects, or activities that will result in a change in OPG's management of a SEA or the environmental impact of an SEA. The change can be an improvement, such as reduced emissions, or reduced costs of managing the SEA.
- Any new or revised programs, projects or activities that introduce a new environmental aspect, such as a new waste stream or effluent

BUs need not identify programs, projects or activities that will be identified and resourced solely by CO&E – Environment.

Significant Environmental Aspect	Business Unit		
	Nuclear	HTO	BAS
1. Carbon 14 Emissions to air	X		
2. Chemical emissions to water – process effluents (includes hydrazine/morpholine use in nuclear)	X	X	
[redacted]			
4. Equipment leakages – from oil filled equipment	X	X	X
5. Fish impingement/entrainment/barriers	X	X	
6. Habitat alteration of natural habitat (loss or creation) – includes the biodiversity program	X	X	X
7. Spills arising from materials and waste handling	X	X	X
8. Tritium emissions to air, water, groundwater	X		
9. Thermal emissions to water	X	X	
10. Water flows and levels		X	
11. Low and intermediate level radioactive waste	X		

New Environmental Legislation

No new or revised environmental legislation requiring consideration in the 2014-2016 BP has been identified. Proposed changes in the Federal Environmental Assessment Act requirements and the Fisheries Act, which are expected to reduce overall administrative burden, and emerging. Provincial and Federal regulation to restrict greenhouse gas emissions, which are not expected to materially affect OPG's operations, will be considered in future business plans after the regulations have been finalized.

To meet the requirements of the Heritage Act, a program of heritage evaluations may be required at some hydroelectric sites during the period of the business plan. CO&E – Environment will advise HTO on requirements to be addressed in business plan submissions.

5.14 BUSINESS PLANNING PROCESS REVIEW — CONTACT: JENNIFER RUZ

As part of Business Transformation, Finance is currently leading a review of the business planning process, with implementation of any resulting changes commencing as part of next year's business planning process. ***This review will not impact the 2014-2016 business planning process.***

The objectives of the review are two-fold: solicit feedback from the BUs in order to better understand the planning effort drivers and opportunities for improvement, and develop a more streamlined and standard approach to business planning in order to address customer feedback and reduce overall effort.

Significant areas of focus of the review include:

- Identification of key planning data to reduce or eliminate collection of unnecessary information
- Clarification of accountabilities
- Introduction of stronger connections with performance metrics, targets and strategy communicated at the start of the planning process
- Implementation of industry leading practices

Finance is in the process of working with the BUs to gather information and feedback from across the company, and a cross-functional project committee has been created to validate the current state findings. Over the summer months in 2013, the project committee will create the conceptual and high-level process design based on the feedback received and leading practices. An implementation plan and roadmap will be produced in the fall of 2013, with any changes to the business planning process beginning to take effect as part of the next business planning cycle in 2014.

For further information, please contact Jennifer Ruz in BP&R (400-2108 at Head Office).

AMPCO Interrogatory #004

Ref: Exhibit A2, Tab 2, Schedule 1, Business Planning and Budgeting

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

a) Please discuss how the business planning process/instructions that underpin the 2013-2015 business plan (Exhibit A2, Tab 2 Schedule 1, Attachment 1) differ from the business planning process/instructions that underpin the 2014-2016 business plan (Exhibit N1, Tab 1, Schedule 1, Attachment 4).

b) Attachment 1: A Board memorandum "Recommendation for submission to the Board of Directors" dated May 16, 2013 accompanied the 2013-2015 Business Plan dated May 16, 2013. Please provide the Board memorandum to the Board of Directors that accompanied the 2014-2016 Business Plan dated November 14, 2013 filed at Exhibit N1, Tab 1, Schedule 1, Attachment 4.

c) Please discuss any key aspects of the 2014-2016 business planning process that differ from those in EB-2010-0008.

d) Page 2 – OPG states it recognizes the impact of its operations on ratepayers and takes into consideration such impacts when setting its business planning targets and guidelines.
Please discuss specifically the process OPG follows to take the impact on rate payers into consideration when developing its plan, setting its targets and determining payment amount increases.

e) Page 3 – OPG employs leading practices in its business planning process. Please summarize specifically what OPG considers to be leading practices.

f) Page 3 – OPG indicates it ensures financial targets are held at an appropriate level of detail in the organization. Please explain this statement more fully and provide examples of how this is implemented in the organization.

g) Page 3 – OPG indicates business planning guidelines (in the areas of capital, OM&A and staff levels) were developed that drive staff reductions. Please confirm the guidelines referenced in the above statement refers to the 2013-2015 Business Planning Instructions filed at Exhibit A2 Tab 2 Schedule 1 Attachment 2. If not, please provide a copy of these business planning guidelines.

h) Page 4 – OPG indicates reductions that were previously planned for 2015 were advanced to 2013, thus helping to manage costs for the 2013 and 2014 period. Please explain more fully and provide details.

i) Page 4 – Please provide more details on how OPG achieves work prioritization across and between business unit plans addresses trade-offs.

j) Page 4 – Please discuss how the significant risks in the 2014-2016 business plan differ from the 2013-2015 business plan.

k) Page 4 – Please confirm when the Province provided final concurrence with the OPG Board-approved 2014-2016 Business Plan.

Response

a) There are no significant differences between the 2014 - 2016 and 2013 - 2015 business planning ("BP") processes for OPG's regulated operations.

The key process changes include:

- Specific new information requirements for the newly regulated hydroelectric facilities.
- Use of guidelines for capital expenditures and project OM&A.
- More explicitly stated requirements and planning accountabilities for certain information submissions.
- A simplified process whereby the payroll burden rate included in standard labour rates in the 2013 - 2015 BP remains unchanged in the 2014 - 2016 BP for 2014 and 2015. Any changes to benefit costs are held centrally at the corporate level.
- A requirement to reflect Business Transformation initiatives in planning submissions.
- Updated environmental planning requirements.
- A new requirement to identify cyber-security project requirements.

b) The Board memorandum that accompanied the 2014 - 2016 Business Plan is provided as Attachment 1 to this response.

c) The main change in the 2014 - 2016 business planning process is a much greater emphasis on headcount reductions. Staff levels are more prominent in top down target setting, and resource envelope levels reflect a drive to reduce headcount and costs.

The 2014 - 2016 planning process also reflects a stronger central role in direction setting, as, in part, evident from the more prescriptive nature of the 2014 - 2016 Business Planning Instructions provided in Ex. L-1.2-1 Staff-004. Additionally, the number of budget holders across the organization has been reduced in an effort to streamline the process. Furthermore, a more streamlined approach for managing changes in benefit cost estimates was adopted.

Finally, the planning process that underpins the EB-2010-0008 payment amounts was conducted in 2009 for a five-year period in producing the 2010 - 2014 Business Plan. The

2014 - 2016 planning process was for a three-year business plan period, as noted in Ex. A2-2-1, page 3. As noted in part b) above, the 2014 - 2016 business planning process also introduced specific top-down guidelines for capital expenditures and project OM&A.

d) A fundamental thrust in our approach to business planning is a focus on cost reduction and efficiencies. As an organization that is primarily regulated, this focus has a direct positive impact on customer bills. This approach is being reinforced through the organization using communications related to Business Transformation.

e) OPG considers leading practice in business planning to be an effective, integrated process that aligns business plans and budgets with corporate strategy using a flexible model with key stakeholder engagement and the appropriate level of detail. The key attributes of an effective business planning process are timeliness, efficiency, accuracy, transparency, depth, insight and clarity.

f) The business plan as presented is at a high level of detail (by Business Unit). The process of assigning budgets to lower levels in the organization and producing cost reports and managing to variances at those levels is an important aspect of OPG's financial control. OPG reviews the levels at which budgets are held and assesses their appropriateness between too granular versus too high level. OPG continues to manage and monitor that balance. As well, costs are broken down into key elements of cost for variance analysis purposes.

g) Confirmed.

h) OPG sets three year business plan targets for each business unit on an annual basis. Given the company's focus on reducing headcount to achieve labour savings, OPG has been setting headcount targets, in addition to financial and operational targets. The 2012 - 2014 Business Plan had headcount targets for each business unit for 2012, 2013, and 2014. When targets were being set for the 2013 - 2015 Business Plan, the normal practice would have been to use the 2013 and 2014 targets from the 2012 - 2014 Business Plan as a starting point and develop a new target for 2015. However, OPG set more aggressive targets for 2013 and 2014 by advancing to 2013 the headcount targets it was initially planning to use for 2015, and making further reductions in 2014 and 2015. Once headcount targets were reduced, OM&A targets were also adjusted.

i) Business Unit plans are reviewed by the CEO, CFO and are subject to discussion at the Executive Level. Within the resource envelopes provided, tradeoffs between business units are subject to discussion at the executive level and agreement of the CEO. Within each business unit, tradeoffs are also required in terms of work prioritization to manage within operating OM&A budgets as well as project budgets. Each Business Unit undertakes a project prioritization process to determine the required investment in project activities (both OM&A and Capital projects), within a resource envelope that is approved for that line of business. Benchmark investment levels as well as plant condition and lifecycle plans if available are all utilized.

j) With respect to OPG's regulated operations, there are no significant differences in the risks associated with the 2014 - 2016 Business Plan and the 2013 - 2015 Business Plan. The main risk continues to be the negative impact on income, credit metrics and cash flow if forecast regulated revenue levels are not achieved.

k) To date, the Ministers of Energy and Finance have not provided final concurrence with OPG's 2014 - 2016 Business Plan. The Government has changed the process for providing concurrence to include a formal submission to and review by the Treasury Board of Cabinet. The timing of those submissions and reviews is outside of OPG's control. Staff within the Ministries of Energy and Finance have not raised any issues with the 2014 - 2016 Business Plan as submitted.

Recommendation for Submission to the Board of Directors

November 14, 2013

OPG's 2014-2016 Business Plan

EXECUTIVE SUMMARY

OPG is seeking Board approval of its 2014-2016 Business Plan. The 2014-2016 Business Plan establishes the financial and operational budget for 2014 which will be used as the control base against which actual results will be measured and assessed, and provides a two-year financial outlook for planning purposes.

The 2014-2016 Business Plan reflects OPG's goal of being Ontario's low-cost electricity generator of choice and its corporate strategies of financial sustainability, performance excellence, and project excellence. In developing the business plan, OPG has recognized the impact of its operations on ratepayers by establishing challenging targets and implementing efficiency improvements. OPG expects to achieve its committed headcount reductions from ongoing operations of 2,000 employees by the end of 2015, with a further reduction of over 300 employees expected in 2016.

The 2014-2016 Business Plan forecasts net income to [redacted] The improvement in income is primarily due to an increase in regulated base rates for the currently regulated assets, regulation of the unregulated hydroelectric stations, and the [redacted] In addition, a one-time extraordinary gain of approximately $300 M is expected to be realized in 2014. The gain is related to the recognition of a regulatory asset for income taxes, effective upon regulation of the unregulated hydroelectric stations.

The 2014-2016 Business Plan is subject to several significant risks, including the ability to achieve forecast regulated revenue levels.

The attached document provides details with respect to OPG's 2014-2016 Business Plan. The Business Plan incorporates the 2014-2016 OM&A expenses and capital expenditure plans provided to the Committees of the Board for Nuclear, Hydro/Thermal, and Business and Administrative Services.

RECOMMENDATION

That the Board of Directors approve the 2014-2016 Business Plan. The 2014 budget reflected in the plan will serve as the control base against which actual results will be measured and assessed.

Recommended By:

"Original Signed By"
Donn Hanbidge
Chief Financial Officer

Approved for submission to the Board of Directors:

"Original Signed By"
Tom Mitchell
President and Chief Executive Officer

This Board memorandum was reviewed and approved for submission to the Board of Directors by the Audit and Finance Committee on November 13, 2013.

AMPCO Interrogatory #005

Ref: Exhibit A2, Tab 2, Schedule 1, Page 2

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Preamble: OPG indicates its overall generation capacity will decline by 25 per cent between 2015 and 2020 as the remaining coal units retire and the Pickering nuclear plant ceases operations around 2020.

In considering the above, please discuss OPG's longer term 10 year business plan outlook including emerging issues and proposed spending levels beyond 2016 and include any supporting materials such as memorandums, reports and presentations to OPG's Board of Directors that address this issue.

Response

Information beyond the 2014 / 2015 test period does not impact the setting of rates for this application and, therefore, is not relevant.

AMPCO Interrogatory #006

Ref: Exhibit A4, Tab 1, Schedule 1, Business Transformation

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

a) Page 1 – OPG will use attrition to reduce its year-end 2015 staff level by 1,300 employees which is expected to reduce OPG's OM&A by $550 M between 2011 and 2015 attributable to regulated operations.
   i) Please restate these employee reductions based on FTEs.
   iii) The Auditor General's Report released in December 2013 reviewed OPG's Human Resources and found no direct correlation between Business Transformation initiatives and positions eliminated through attrition. Please discuss.

b) Page 5 – Staff reductions of approximately 1,000 were achieved by the end of 2012, with the 20132015 Business Plan targeting the remaining reduction of 1,000 employees.
   i) Please provide the actual reductions for 2013 and forecast reductions for 2014 and 2015 and the corresponding savings broken down by regulated and non-regulated.
   ii) Please provide any changes in 2014 and 2015 reductions based on the 2014 to 2016 Business Plan.
   iii) Please provide the staff reductions planned for 2016.

e) Page 6 – Chart – Trending Hires and Staff Levels -Please provide the actual hires for 2013.

f) Please provide a table that shows FTE vacancies for 2010 to 2013 actuals and forecast for 2014 and 2015.

g) Page 6 – Please provide a description of the 5 new behaviours identified as culture shifts that OPG must accomplish in order to sustain change.

h) Page 6 – Please provide the original and updated OPG Values.

i) Page 8 – For 2013 to 2015 please provide details on the scope of work for external consulting assistance for business transformation and explain how the costs are allocated between regulated and non-regulated.

j) Page 8 – Please provide forecast business transformation costs for 2016 to 2020.

k) Page 8 – Please discuss if the internal staffing costs for business transformation for the years 2011 to 2015 include new hires.

l) Please summarize the savings resulting from Business Transformation activities from 2010-2015.

Response

a) i) Please refer to Ex L-6.8-1 Staff-100.

iii) OPG's Business Transformation ("BT") objective is to reduce staff levels by 2,000 employees by the end of 2015. Based on staffing levels in 2011, this represents close to a 20% reduction in OPG's headcount. The magnitude of these reductions required a significant focus on streamlining and transforming the way OPG does things in order to be able to operate sustainably at these lower staffing levels.

To achieve the work reductions required, each BU identified areas where work could be streamlined or eliminated and developed initiatives to achieve these changes. The initiatives were developed throughout OPG; they were not limited to areas where attrition was expected to take place.

For the 2013 - 2015 Business Plan, headcount targets were developed based on expected attrition over the period. Given OPG's workforce demographics, attrition is the most cost effective way to meet our headcount reduction targets.

However, attrition does not always take place in the areas in the company where work has been eliminated. To align the staff and the work, OPG plans to move resources from areas where the work was eliminated to areas where attrition may have outpaced work elimination. About 90% of OPG's workforce is unionized and organizational changes must be managed through specific processes in OPG's collective agreements. OPG has commenced this redeployment process to achieve the necessary alignment between staff levels and work requirements and to provide greater flexibility in staff deployment in the future.

For instance, placing employees in broader job documents allows OPG greater flexibility to assign staff new work. This helps OPG manage gaps between where work has been eliminated and attrition has occurred. For example, OPG is moving to place all of the section head positions in the CIO group under one job document. Currently there are 16 positions with 8 different job documents. By placing all 16 positions under one job document, OPG will gain flexibility to reassign work across the broader pool of 16 positions. Other examples of this include moving to common job documents for roles across hydro and thermal plants and standardizing environmental advisors into one job document to facilitate the adoption of a single OPG-wide Environmental Management System.

b)

i) The actual headcount reduction from ongoing operations for all of OPG in 2013 was 579 staff, of which approximately 450 staff is attributed to the regulated operations including newly regulated hydroelectric. The resulting additional savings in 2013, calculated using the methodology described in Ex. L-6.8-4 CCC-022, are approximately $20M for the regulated operations, inclusive of the newly regulated hydroelectric facilities.

The 2014 and 2015 headcount reductions and corresponding savings per OPG's 2013 - 2015 Business Plan are found in Ex. L-6.8-4 CCC-022.

ii) As noted in Ex. N1-1-1, OPG has updated its Application for three material impacts arising from the 2014 - 2016 Business Plan. Plan-over-plan changes in forecast headcount reductions, if any, is not one of those impacts and would be reflected in the $26M of additional OM&A costs that OPG is not seeking to recover. As such, the requested information is not relevant.

iii) The information for 2016 is not provided as it is beyond the test period.

e) The actual hires for 2013 were 83.

f) OPG does not track FTE or headcount vacancies. Therefore, information on 2010 - 2013 actual and 2014 and 2015 forecast vacancies is unavailable.

g) Refer to Ex L-1.2-17 SEC-012 for a description of the 5 new behaviours.

h) OPG's original values:

- Integrity
- Respect
- Commitment
- Teamwork
- Safety

OPG's updated values:

- Safety
- Integrity
- Excellence
- People and Citizenship

OPG's updated values are outlined in the Code of Business Conduct which is provided with Ex L-1.2-17 SEC-012.

i) For 2013 - 2015, the scope of work for external consulting assistance is focused on change management and organizational design support.

The external consultants are providing expertise in the following areas:

- Change management to support the move to the centre-led organization and large, multi-phased complex transformational change initiatives
- Direct support to business units to manage business transformation

- Establishing a Centre of Expertise for Change Management for OPG (methodology, tools, knowledge transfer, integrated change planning, business impact management etc.)
- Organizational design expertise to support the move to the centre-led organization
- Development and implementation of an organization change control and organization implementation processes
- Identification of learning needs and development of learning programs to address needs to transition to and operate in a centre-led organization and to address future capability needs

The Business Transformation costs were allocated to each business unit based on the percentage of OM&A and capital spend for each business unit compared to OPG's overall OM&A and capital spend. This allocation approach is commonly used when there are no applicable cost drivers available.

j) The forecast of Business Transformation costs for 2016 - 2020 are beyond the test period.

k) There were no new hires included in the business transformation staffing costs.

l) Please refer to Ex L-6.8-4 CCC-022 for a breakdown on the savings resulting from BT in 2010 - 2015.

AMPCO Interrogatory #007

Ref: Exhibit A1, Tab 5, Schedule 1

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Preamble: OPG provides its Corporate Organizational Chart a) Please provide the date of the Corporate Organizational Chart. b) Does the Corporate Organizational Chart reflect the full outcome of Business Transformation?

Response

a) The date of the Corporate Organizational Chart is September 27, 2013.

b) At the level presented, the chart reflects the full outcome of Business Transformation's move to a centre-led organization. While all management staff have been aligned to the centre-led organization, the redeployment of represented staff is ongoing.

CCC Interrogatory #004

Ref: Ex. A2/T2/S1/p. 3

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide copies of all of the "guidelines" for the 2013-2015 business planning process.

Response

The guidelines referred to at the reference are the 2013-2015 Business Planning Instructions filed at Ex. A2-2-1 Attachment 2.

CCC Interrogatory #005

Ref: Ex. A4/T1/S1/p. 2

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide a copy of the KPMG Efficiency Review of OPG.

Response

Please see Ex L-6.8-17 SEC-116.

SEC Interrogatory #002

Ref: A1-4-1/p.2

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide the most recent "3-5 year performance targets" referred to, including details of all "key measures" agreed upon with the Shareholder or the Minister of Finance, and including all benchmarking information related to those targets. Please provide all presentations, memoranda or other documents used to explain those performance targets, key measures or benchmarking information to the Applicant's Board of Directors, to the Shareholder, or to the Minister of Finance.

Response

The 3 - 5 year performance targets and key measures referenced in the above question are provided to OPG's Shareholder through OPG's annual business plans.

OPG's last two business plans are filed at Ex. A2-2-1, Attachment 1 (2013 - 2015 Business Plan) and at Ex. N1-1-1, Attachment 4 (2014 - 2016 Business Plan). OPG declines to provide the requested additional documents for the reasons given in Exhibit L-01.4-4 CCC-006(d).

SEC Interrogatory #003

Ref: A1-4-1/p.3

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide the most recent "3-5 year investment plan" referred to. Please provide all presentations, memoranda or other documents used to explain that investment plan to the Applicant's Board of Directors, to the Shareholder, or to the Minister of Finance.

Response

See Ex. L-01.2-17 SEC-002.

SEC Interrogatory #004

Ref: A1-4-1/p.3

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide the last five "timely reports and information on major developments and issues" provided by OPG to the Shareholder pursuant to section E1. Please provide the last five reports under that section provided by the Shareholder to OPG.

Response

OPG declines to produce the requested documents on the basis of relevance. These documents formed no part of OPG's Application and have no probative value in deciding it. To the extent that any of the major developments and issues have impacted OPG's test period revenue requirement, they are fully discussed in OPG's Application.

SEC Interrogatory #005

Ref: A2-1-1-Attach 1/p.6, and A4-1-1

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide the original plan setting out the Business Transformation Initiative, including any supporting sub-plans. Please provide the last three reports to the Board of Directors on the results of the Business Transformation Initiative.

Response

Attachment 1 is the Business Transformation Plan submitted to OPG's Board of Directors. Attachments 2, 3 and 4 are the last three quarterly reports to OPG's Board of Directors. OPG has provided this material in recognition of the importance of this key initiative to controlling costs in the test period.

Business Transformation Project

CHRC Meeting

December 14, 2011

ONTARIO POWER GENERATION

Agenda

- Objectives
- Organizational Structure
- High Level Implementation Schedule
- High Level Cost/Benefit Summary
- Significant Risks associated with implementation
- Labour Relations Strategy
- Change Management
- Communication Plan

Business Transformation Objectives

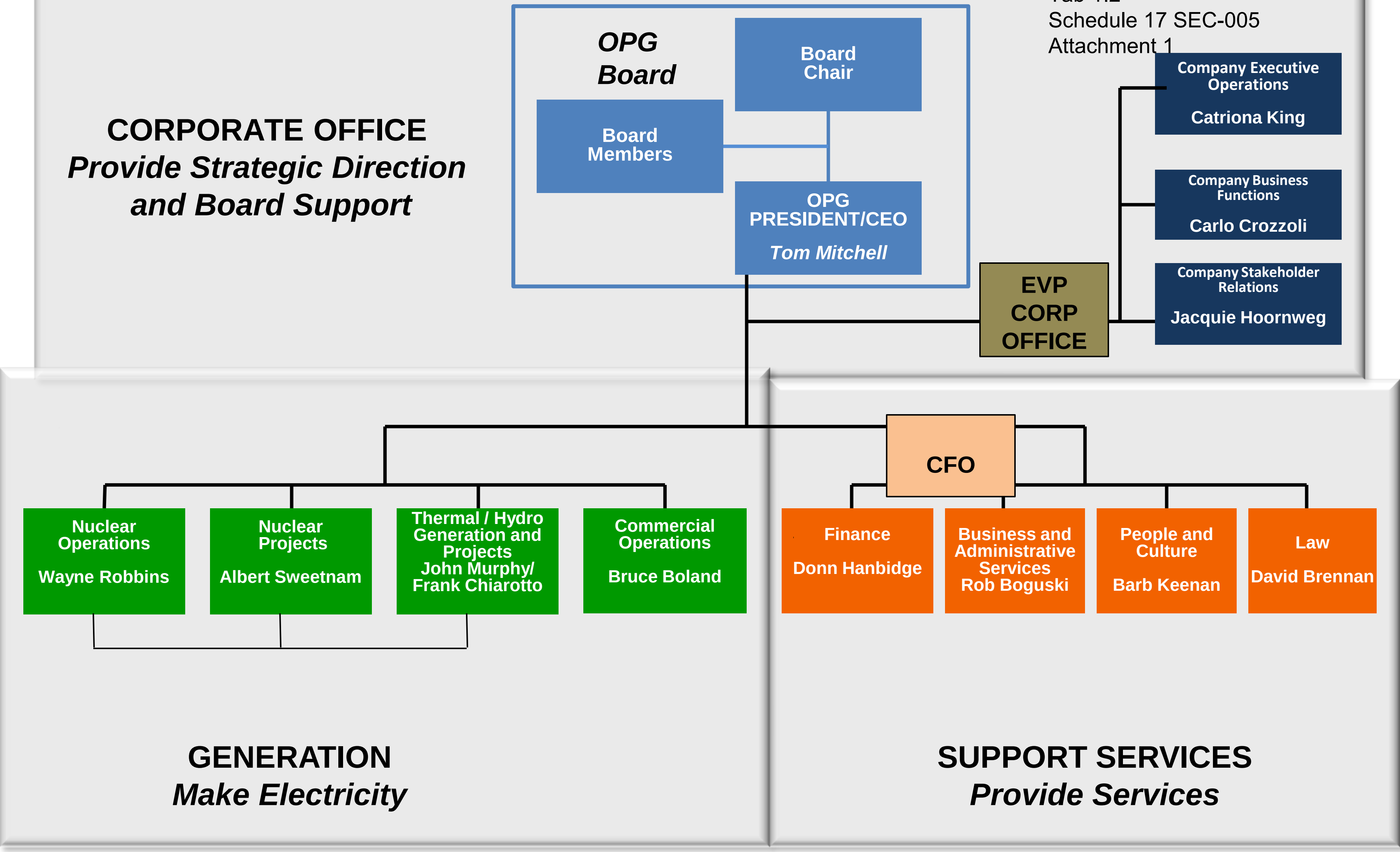
- Transform OPG for the future to create a scalable organizational model to meet changing market conditions and capitalize on future business opportunities.
- Ensure successful implementation of 2012-2014 Business Plan and drive the organization to median benchmarks or better.
- Additional savings to be realized late 2014/early 2015

Organizational Design Principles

- Create an Integrated Operating Model to ensure BTS objectives are met
- No compromise on safety or reliability
- Deliver on the 2012 – 2014 Business Plan
- Begin the transition to the new operating model on January 1, 2012
- Ownership of the execution transitions to the ELT and their current direct reports during Q1, 2012 with a defined project infrastructure
- Complete the transition in Q1, 2015

Filed: 2014-03-19
EB-2013-0321
Exhibit L
Tab 1.2
Schedule 17 SEC-005
Attachment 1

Organizational Structure

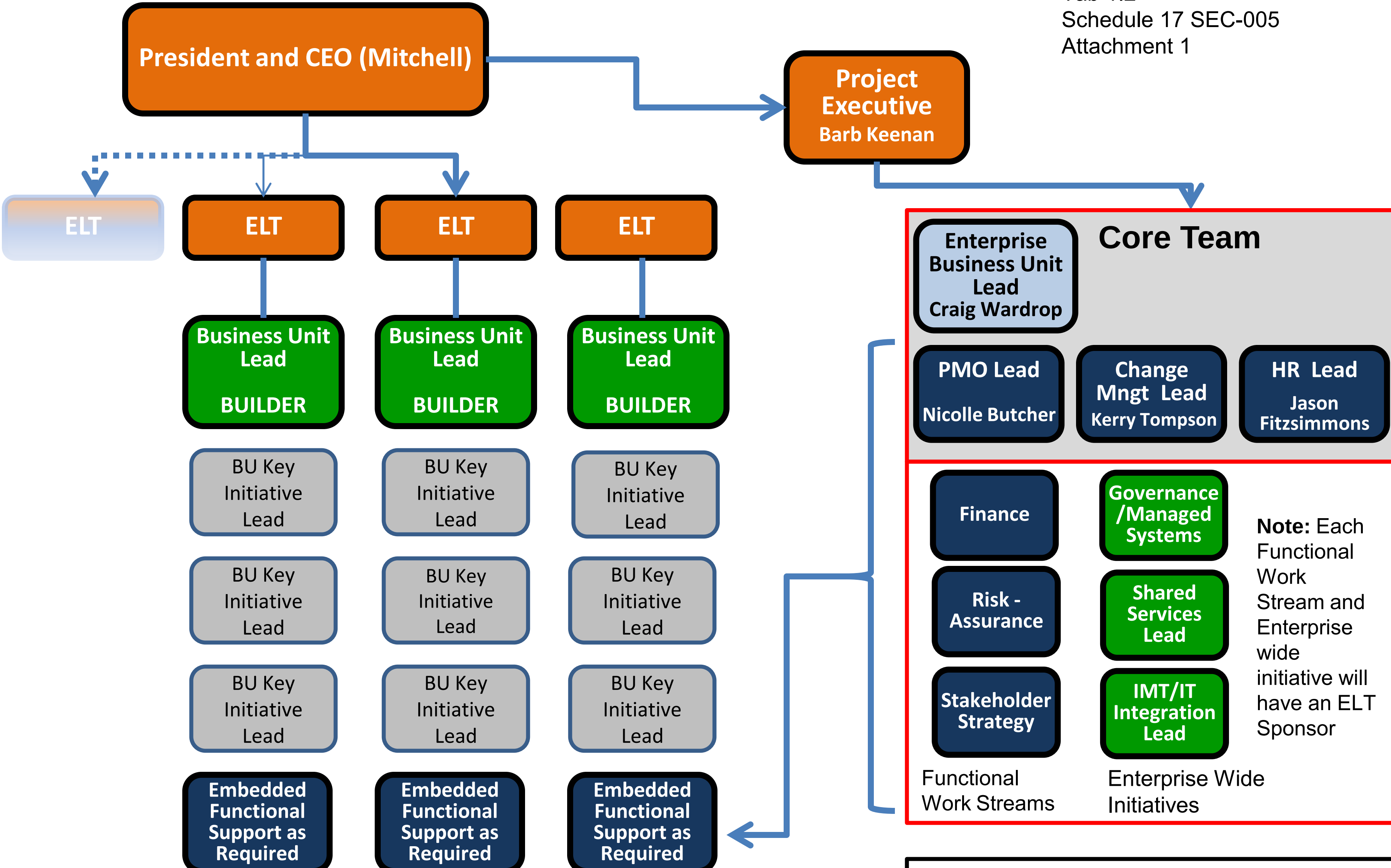


OPG CONFIDENTIAL

ONTARIO POWER GENERATION

Filed: 2014-03-19
EB-2013-0321
Exhibit 1
Tab 1.2
Schedule 17 SEC-005
Attachment 1

BT Project Implementation Structure



Accountability for Implementation

Accountability for Process, Integration and Support

Level 2 Schedule

2012 | 2013 | 2014 | 2015

1. Build the Foundation

A. Pre-transition planning.
B. Foundational initiatives

Outcomes of Phase 1:
- Broad SLT involved
- Foundational initiatives and "quick wins" launched completed or underway with progress
- Plan finalized and integrated with business plan priorities.
- Selection Preparation
- Attrition aggressively managed.

2. Initiate Centre-Led Organization

A. Align functional accountability to new leaders

Outcomes of Phase 2:
- "Leaders" selected and in place. (L2/some L3)
- Organization transitioned at highest level.
- Centre-led organizations "kicked off".
- Establish centre-led transition "partnering agreements"
- Attrition aggressively managed.

3. Transform the Delivery Model

A. Update streamlined managed systems/process.
B. Design and select for centre-led organization. (80/20)

Outcomes of Phase 3:
- Managed systems (processes, procedures, etc) streamlined and implemented.
- Shared Services delivery model defined and processes established.
- New organization structures defined – bring as much of target organization forward as possible.
- All management group positions selected
- JRPT completed placing all people into new organization structure, including redeployments. Units of Application aligned to new functional structure, and people assigned to appropriate functional units.
- Updated term sheets with new service delivery expectations.
- New centre-led teams "kicked off".
- Attrition aggressively managed.

4. Finalize Centre-led Organization

A. Implement final organization.
B. Complete final reductions.

Outcomes of Phase 4:
- Final target organization implemented.
- Shared Services fully operational and functioning
- JRPT's implemented by function as necessary.
- **Full and final reductions taken at the end of 2104/early 2015..**

ONTARIO POWER GENERATION

Financial Objectives

- 2012- 2014 business plan incorporates significant headcount reductions of ~1,000 regular staff and generally align with expected attrition over the planning period
- OM&A reductions embedded in the business plan will be incorporated into the 2012 rate application to the Ontario Energy Board for 2013/2014 rate
- Headcount reductions would notionally translate to OM&A savings of $75 Million over this period, but are largely offset by cost pressures due to labour escalation and other factors
- Work undertaken as part of business Transformation will increase confidence in meeting headcount targets by
  - changing organization structure and realigning work
  - modifying service delivery model
  - developing implementation plans for process improvements contemplated as part of business plan and identifying additional opportunities to achieve targets
- Additional headcount reductions of ~1500 will take place in the late 2014/early 2015 timeframe as other initiatives come to fruition.
- Annual OM&A savings in 2015 and beyond are expected to be ~$250M annually

ONTARIO POWER GENERATION

Key Risk Summary

- **Leadership Challenge**
  - Sustained Leadership Alignment
  - Staff Engagement
  - Skills Retention
- **Results Not Achieved**
  - Gains not as projected due to planning level at this stage
  - Attrition not as projected
  - LR Complexity
  - Change Capacity
- **Stakeholder Influence**
  - CNSC
  - Shareholder
  - OEB

Labour Relations Strategy

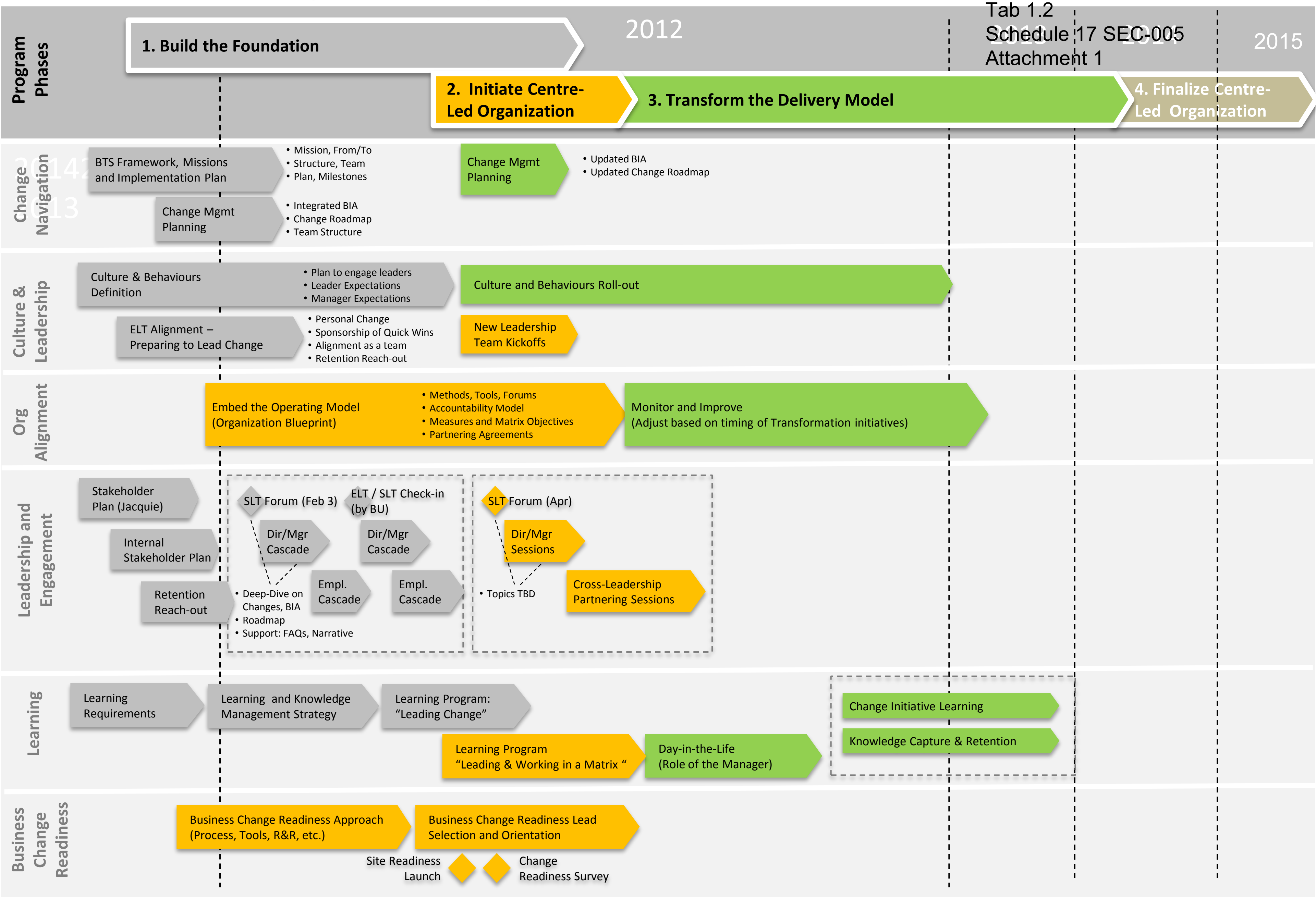
- Redeploy to new structure with no Surplus (Article 64B).
- The Business Transformation is changing the company to such a significant degree that new Units of Applications (UA) must be jointly created.
- Aggressively manage performance and attrition.
- Attrition should be sufficient to meet the 2012 – 2014 Business Plan.
- Work within the bounds of the current collective agreements
- Selected, targeted packages in early 2015 if attrition does not achieve desired results

Change Management Challenges

1. Given our history, there is doubt around whether or not there is a compelling and sustaining ‘burning platform’ for change
2. The spotlight is on ELT, and there is question if ELT is really aligned and owning/driving the change
3. Complexity of the stakeholder landscape and their competing needs are creating challenges to communicate and move ahead with certainty.
4. While leaders agreed with the operating model, there was general concern that trust and accountability together are fundamental to it’s success, and are not currently present.
5. There is recognition of the vital importance of culture as a change driver that will ensure either success or failure of this transformation
6. There is absence of a clear understanding of OPG’s identity and future vision
7. A critical mass of Middle Manager/FLM who can ‘own the change’ will be very important. Impacts to this role will need to be carefully considered while ensuring they are set up to effectively lead change.
8. Importance of appropriately timing the transformation – neither too fast nor too slow

Filed: 2014-03-19
EB-2013-0321
Exhibit L
Tab 1.2
Schedule 17 SEC-005
Attachment 1

Change Management Roadmap (to 2012 Q3)



Stakeholder Relations

Communication goals and risk mitigation:

- **Synchronize interdependent messaging**
  - Business Transformation / Ontario Energy Board application and hearing / Power Workers Union contract negotiations / Shareholder inputs: Auditor general report, Drummond report, 2012 spring budget / Salary disclosure / Quarterly financials / Nuclear plant licensing activities
- **Enable culture and engage employees in change**
  - A stepped approach to messaging tied to change management activities to enable culture evolution to occur.
  - Change implementation and communication owned and led by the line; accepted, understood and adopted by employees.
- **Earn value recognition from stakeholders / shareholder for BT initiative and outcomes**
  - Achieve maximum value and recognition that OPG is acting as a responsibly-managed, efficient and effective company that should be the trusted generator of choice for Ontario.

Report for Submission to the Compensation and Human Resources Committee

May 15, 2013

Business Transformation Q1 Update

EXECUTIVE SUMMARY:

The purpose of this report is to provide an update on significant Business Transformation activity completed in the first quarter of 2013. Further, an update on staff reduction numbers in Q1 and project life-to-date numbers are also provided.

Consistent with OPG's mission to be the electricity generator of choice in Ontario, Business Transformation sets the foundation for the creation of an agile, scalable and competitive organization capable of meeting changing market conditions and capitalizing on future business opportunities. In 2012, the Centre-Led organization was initiated, performance improvement initiatives, "quick wins", were completed and the organization design finalized. Much of the Business Transformation effort thus far in 2013, has been focused on the process of redeploying staff from the legacy organization into the newly designed organization. Most prerequisite work is complete putting OPG in a good state of readiness for deployment.

Submitted By:

Original signed by

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Mike Martelli
Project Executive
Business Transformation

Original signed by

____
Barb Keenan
Senior Vice President
People & Culture & Chief Ethics Officer

Ready for Redeployment

Create an agile, scalable, competitive organization capable of meeting changing market conditions while capitalizing on future business opportunities

Managing the Redeployment Process

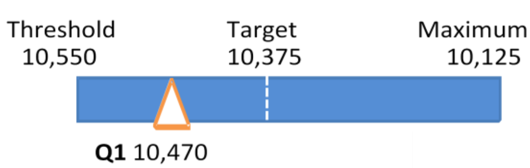
- A redeployment start date has been set for May 24th. The start is symbolized by management's presentation of the new organization details to our unions.
- Organizations were finalized and approved by ELT. This was followed by an organization freeze and a vacancy freeze.
- Joint redeployment training was conducted for both Society and Management redeployment team members.
- Coal Closure language was invoked for Lambton GS, Nanticoke GS and Thunder Bay GS. With agreement from the Society, the Coal Closure process was integrated into the reorganization deployment process (LOU 191)
- Remaining Management Group selections will start concurrently with start of the redeployment process. The expectation is that most remaining MG positions will be filled by the end of Q2. Many of these positions are boundary positions with the Society of Energy Professionals and therefore, could not be filled until formal discussions explaining exclusion criteria were completed.

Managing Redeployment Risk

- A redeployment Impact Assessment was completed and presented to ELT for review and agreement. Impact mitigation plans are in progress and on track to be in place before May 24th.
- To ensure an orderly start to redeployment, a detailed strategy for the presentation of organization details to the unions has been established.
- To ensure consistent messaging to all employees, a communication cascade detailing the organization changes is planned to start days after the organization details are presented to our unions.
- Management continues to meet with union executives on a monthly basis to discuss the details of a centre-led organization and the potential impact to staff.
- A draft Readiness Assessment was presented to ELT in March. Organization changes relating to coal closure and Nuclear Projects reorganization are complete.

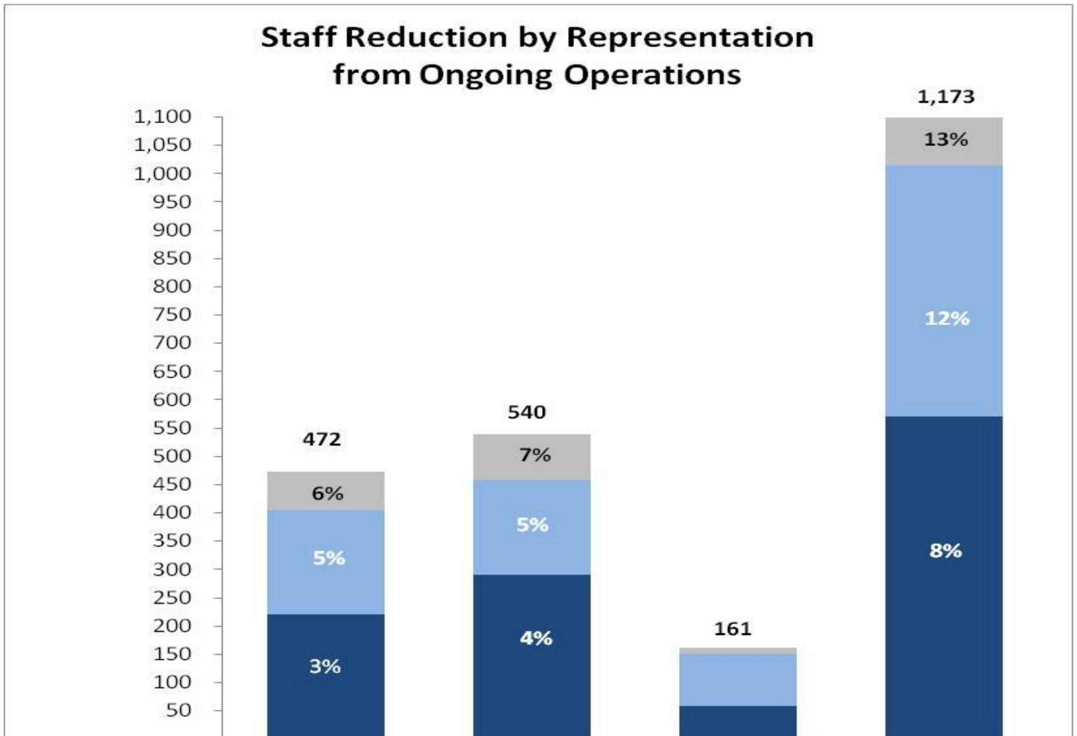
Managing Attrition

- Vacancies continue to be managed aggressively. A hiring freeze is in effect and a gated process for hiring critical operations staff is in place.
- Many vacancies have been held in the Hydro organization to help offset the deployment of Coal Closure staff.
- 2013 Q1 staff reduction from ongoing operations was 161 compared to 156 in Q1 2012 and 129 in Q1 2011.
- OPG headcount from ongoing operations against 2013 performance scorecard is shown below.

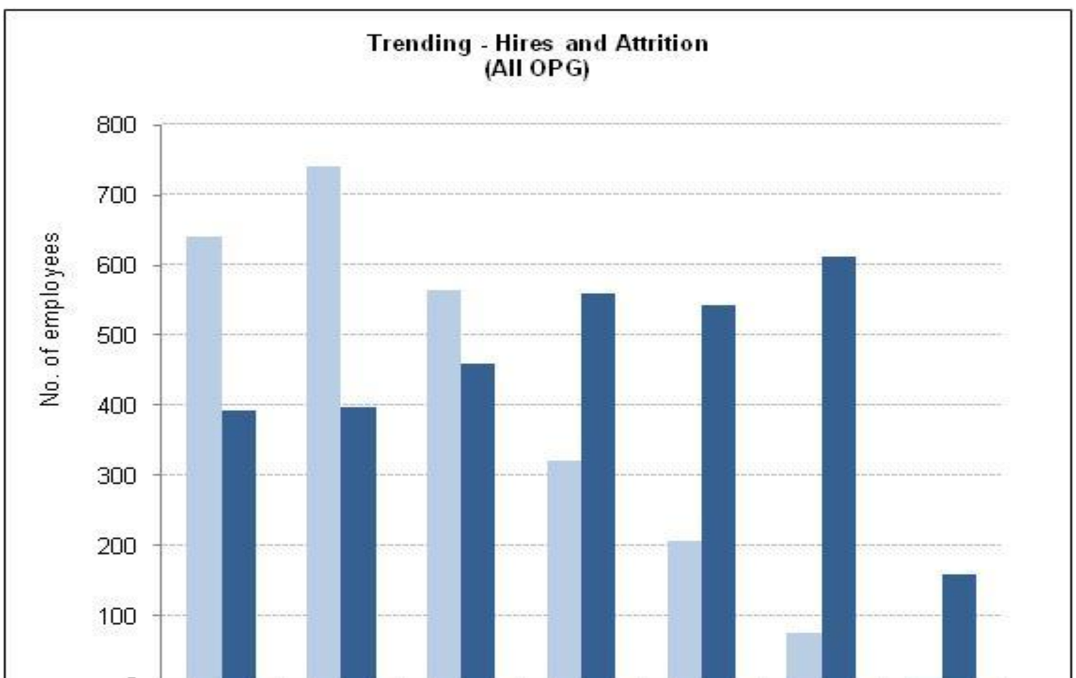


Ready for Redeployment

Create an agile, scalable, competitive organization capable of meeting changing market conditions while capitalizing on future business opportunities



	2011	2012	YTD Mar. 2013	Project to Date
Exec/Mgmt	67	81	11	159
Society	185	168	91	444
PWU	220	291	59	570



	2007	2008	2009	2010	2011	2012	YTD Mar 2013
Hires	641	741	565	322	207	77	10
Attrition	392	398	460	560	542	613	159

Filed: 2014-03-19
EB-2013-0321
Exhibit L
Tab 1.2
Schedule 17 SEC-005
Attachment 3

Report for Submission to the Compensation and Human Resources Committee

August 14, 2013

Business Transformation Q2 Update

EXECUTIVE SUMMARY:

The purpose of this report is to provide an update on significant Business Transformation activities completed in the second quarter of 2013 including an update on staff reduction numbers in Q2 and cumulatively from commencement of the project.

We are in the 3rd Phase, "Transform the Way We Work", of our four phased Business Transformation Plan. In second quarter of 2013 we achieved a significant milestone with the commencement of redeployment for the Society and PWU represented employees. This milestone is the culmination of significant work across the entire leadership team. Information on the organizational structure and the redeployment processes was cascaded out to the employees once the information had been formally handed over to the Unions. We are also continuing to make progress on the key change initiatives and shifting our culture.

Submitted By:

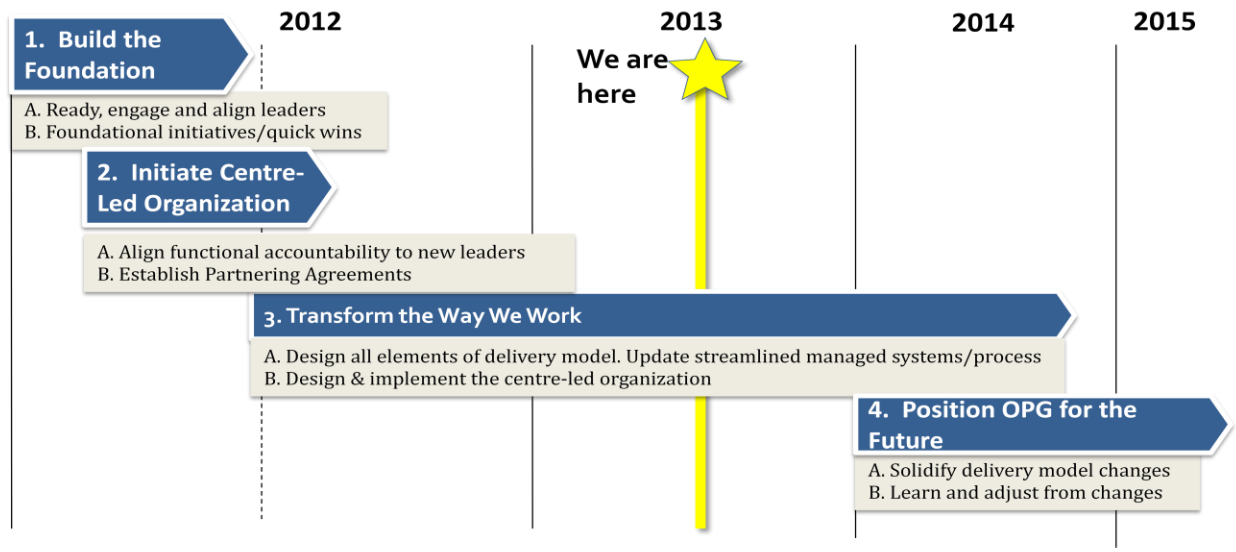
"Original signed by"

Nicolle Butcher
Project Executive
Business Transformation

"Original signed by"

Barb Keenan
Senior Vice President
People & Culture & Chief Ethics Officer

Business Transformation – Transforming the Way We Work through Redeployment and Change Initiatives



We are continuing on Phase 3 of our BT journey – Transform the Way We Work. Having successfully completed Phase 1 and 2, our focus is designing and implementing the centre-led organization, designing delivery models, and streamlining systems and processes to accommodate declining staff numbers. This BT Phase has the biggest impact on individuals so we are starting to receive more union and employee feedback relative to the changes. Our challenge remains staying the course on deployment and change initiatives, maintaining leadership alignment, and reinforcing the cultural changes required to sustain these efforts. The following provides a high level review of the key areas of focus.

Fully Implement the Centre-Led Organization

– The redeployment process commenced on May 24th with the Society and PWU with Management presenting the new organizational designs to the Unions.
– For Society deployment, the Joint Redeployment Planning Team(joint management/union team) is working through the details of the deployment process with the next major step being the issuance of a fact sheet to all employees. Thus far, one dispute has been taken through arbitration for resolution.
– The PWU process is expected to be completed by year end for both nuclear and non-nuclear business units with the new PWU roles expected to be in place early in 2014.
– Remaining Management Group selections will be filled throughout the summer period.

Transforming the Way We Work

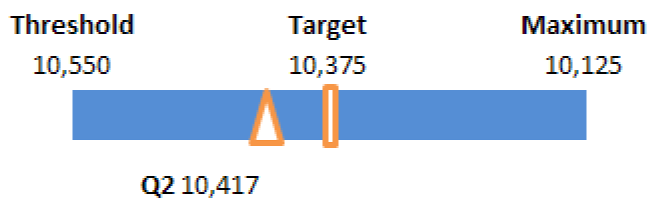
– Work continues in all Business Units on completing their change initiatives to streamline work and ensure the staff reductions achieved through BT are sustainable over the long term.
– The 29 key initiative milestones that are critical for driving BT in 2013 have been included in the BT Corporate Scorecard.
– 15 deliverables have been completed on time and all remaining deliverables are on track for completion as scheduled.

Transforming Our Culture

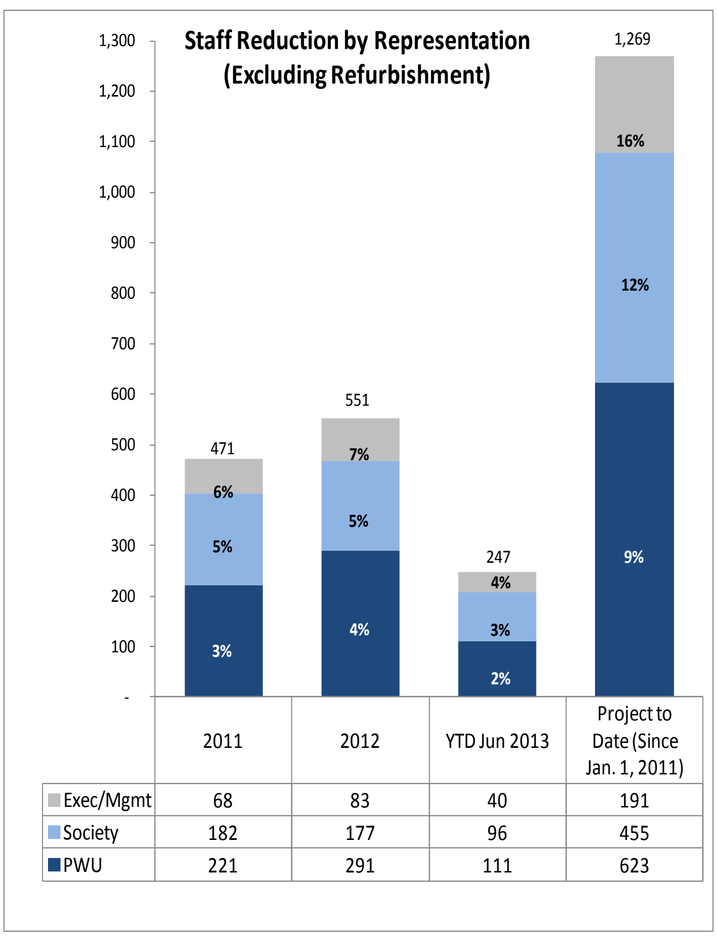
- A Leader's Guide to Culture has been prepared to support leaders in demonstrating and embedding our Values and new Behaviours. The guide, which provides practical tools for teams to use to build the understanding of what it means to live our behaviours, will be rolled out over the coming months.
- A Change Readiness Pulse Check has been prepared to provide management with a status of current levels of understand around OPG's mission and identify areas for additional focus.

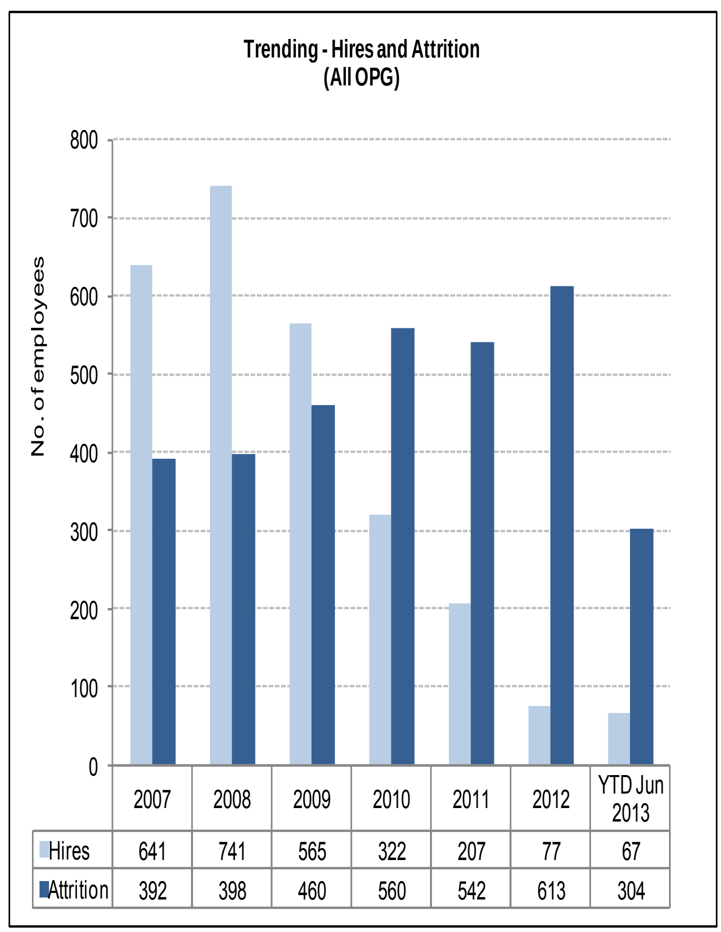
Effectively Managing Attrition

- Vacancies continue to be managed aggressively. Hiring in select areas is allowed to fill critical roles. YTD there have been 67 external hires – a significant portion of which are nuclear engineering trainees hired based on the expected attrition in the coming years.
- OPG Headcount from Ongoing Operations against 2013 performance scorecard targets is shown below, along with detailed graphs showing attrition trends.



Attrition Trends – June 2013





ONTARIO POWER GENERATION

Report for Submission to the Compensation and Human Resources Committee

November 13, 2013

Business Transformation Q3 Update

EXECUTIVE SUMMARY:

The purpose of this report is to provide an update on significant Business Transformation activities completed in the third quarter of 2013 including an update on staff reduction numbers in Q3 and cumulatively from commencement of the project.

We are in the 3rd Phase, "Transform the Way We Work", of our four phased Business Transformation Plan. In the third quarter of 2013, we continued to work through the JRPT processes collaboratively with the Society. There have been 3 issues taken to arbitration for resolution to date. For the PWU redeployment, the focus for the third quarter was on completing the coal closure processes to allow us to better understand the magnitude and skill set of over complement staff.

We are also continuing to make progress on the key change initiatives and shifting our culture. Many of our larger BT initiatives, such as our Human Resources Service Centre, are reaching the final phase of implementation planning with the expectation of significant changes being rolled out in 2014.

Submitted By:

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Nicolle Butcher
Project Executive
Business Transformation

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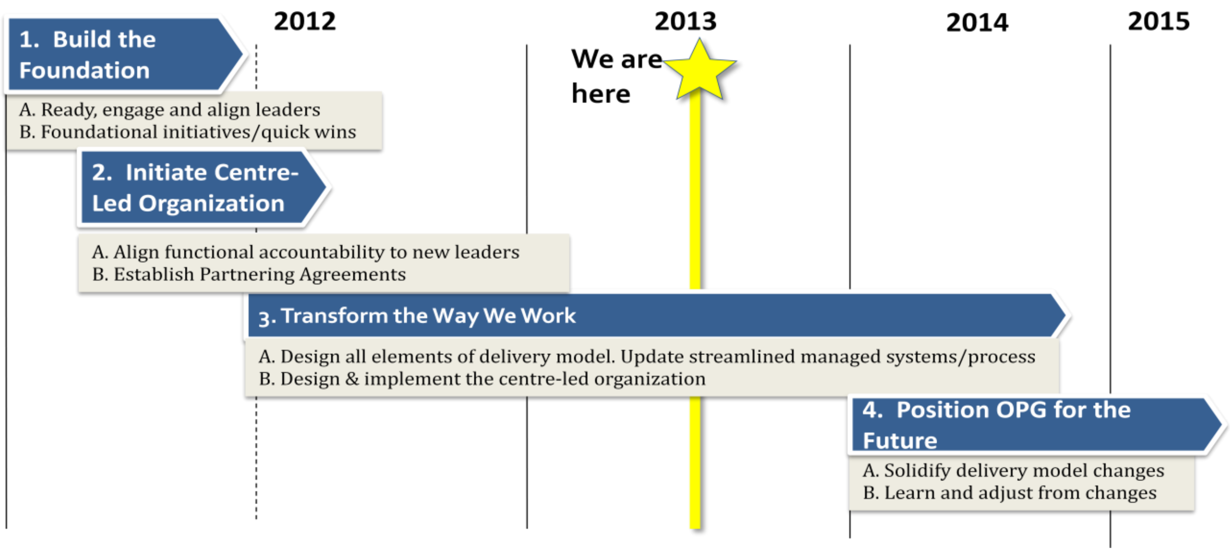
Senior Vice President
People & Culture & Chief Ethics Officer

Business Transformation – Transforming the Way We Work through Redeployment and Change Initiatives



We are continuing on Phase 3 of our BT journey – Transform the Way We Work. Having successfully completed Phase 1 and 2, our focus is designing and implementing the centre-led organization, designing delivery models, and streamlining systems and processes to accommodate declining staff numbers. The centre-led organization design was completed earlier in 2013 and the organization designs were rolled out to employees in late Q2. Continuing discussions on the organization design with the unions has been the focus for Q3, in order to move forward and staff the new organization and realize the benefits of the new design. Momentum is growing around the change initiatives, in that changes are moving from planning to implementation. These changes are starting to push on the need to transform the culture and demonstrate the new behaviours. Our challenge remains staying the course on redeployment and change initiatives, maintaining leadership alignment and commitment, sustaining momentum through a slow redeployment process, and reinforcing the cultural changes required to sustain these efforts. The following provides a high level review of the key areas of focus.

Fully Implement the Centre-Led Organization

– The redeployment process with the Society continues to progress, albeit at a slow pace. Thus far, there have been 3 issues taken to Arbitration. As the process is fundamentally a collaborative one, the Joint Redeployment Planning Team (JRPT) is spending time up front to work through process issues and reaching agreement where possible.
– Given the likelihood of the JRPT process running beyond Q1 of 2014, the BT team is working toward providing the business units with greater flexibility to put temporary arrangements in place to achieve their business objectives without disrupting the JRPT process.

Transforming the Way We Work

– Work continues in all Business Units on completing their change initiatives to streamline work and ensuring the staff reductions achieved through BT are sustainable over the long term.
– A Management Group survey, the "Business Transformation Check-in", has been created, to provide the Enterprise Leadership Team with an assessment on the overall progress of business transformation, and to emphasize focus areas that are required in order to sustain the change over the long term. The "Check-In" has been designed to assess progress with the Senior Leadership Team leading sustained change, and with the broader Management Group understanding and managing change within their teams. The results will be used to identify areas of focus, both at the Business Unit and the OPG level.

– The 23 of the 29 key initiative milestones that are critical for driving BT in 2013 have been completed on time. Of the 6 remaining for Q4, 5 deliverables are on track for completion as scheduled and one is at risk.

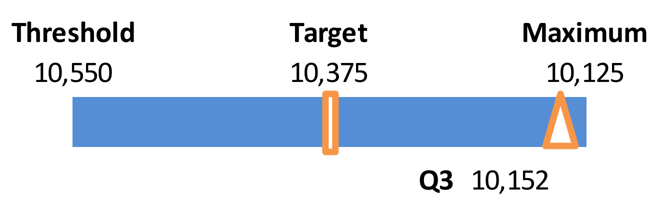
Transforming Our Culture

As outlined in an earlier report, OPG is progressing along 5 paths to culture implementation. The following provides an update on each of these paths for the last 2 quarters of 2013:

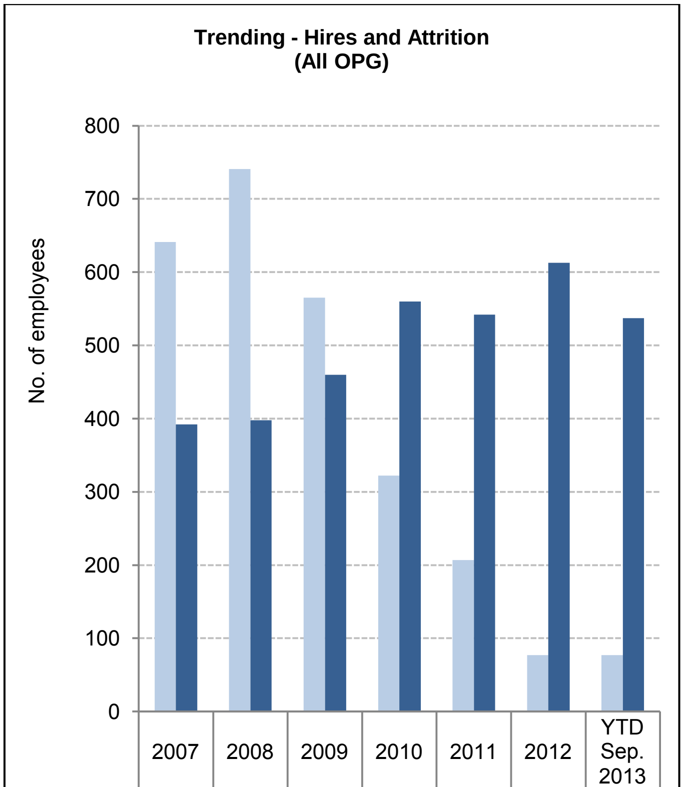
1. **Leader-led, Leader accountable: Prepare and align leaders to lead a shift in culture.** A Leader's Guide to Culture was created, and is in progress of being used, to support leaders in leading culture change in their organizations. Each Business Unit has a culture plan, which is in the process of being executed, which focuses on leader-led accountability for culture change. A key component of many of the BU plans are leadership conversations focused on self-assessment of progress against behaviours, and critical actions needed in order to advance culture change.
2. **Educate and engage staff so they understand what it means for them.** As part of Business Unit culture plans, educating all employees is a focus for 2013.
3. **Make it real through business practices and change initiatives.** Engineering business practices to ensure they align to the desired culture is fundamental, and ensuring stakeholders also align to the desired behaviours. Continued effort is required in this area, and will continue to be tackled through the change initiatives.
4. **Values and Behaviours into HR Practices.** A significant emphasis for culture change is to embed the cultural changes into HR practices, to ensure reinforcement mechanisms were in place. The following HR practices now incorporate values and behaviours, and are part of a larger integrated plan to ensure all HR processes align: Code of Conduct training, 2013 performance review and development planning, recruitment questions, leadership model aligned to behaviours.
5. **Measure and monitor progress.** The "Business Transformation Check-in" is a key opportunity to measure and monitor progress on the cultural transformation. Key questions have been designed to assess OPG's progress in this area.

Effectively Managing Attrition

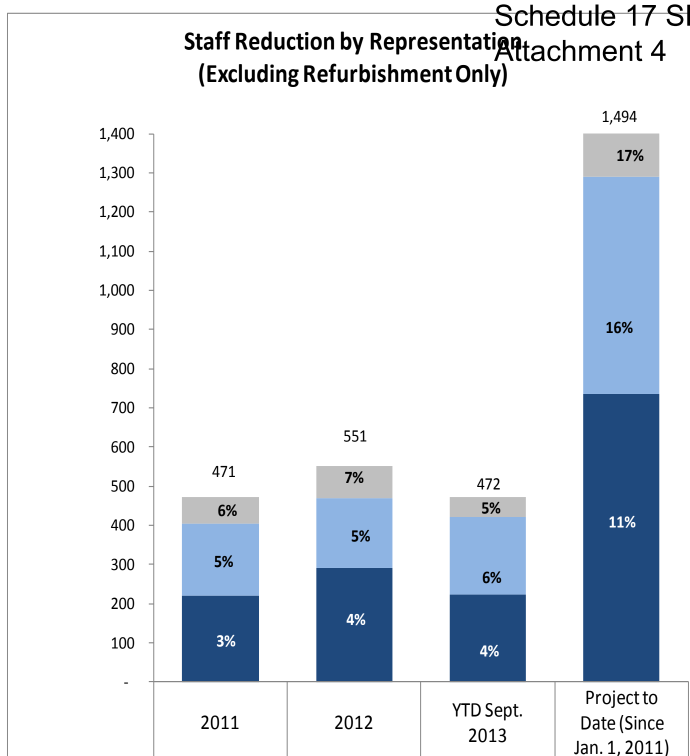
– The OPG headcount has reduced by 1,494 from January 2011 to September 30, 2013. This represents a total project to date reduction of 13% of the OPG total headcount (excluding Darlington Refurbishment).
– OPG Headcount from Ongoing Operations against 2013 performance scorecard targets is shown below, along with detailed graphs showing attrition trends.



Attrition Trends – September 2013



	2007	2008	2009	2010	2011	2012	YTD Sep. 2013
Hires	641	741	565	322	207	77	77
Attrition	392	398	460	560	542	613	537



	2011	2012	YTD Sept. 2013	Project to Date (Since Jan. 1, 2011)
Exec/Mgmt	68	83	52	203
Society	182	177	196	555
PWU	221	291	224	736

SEC Interrogatory #006

Ref: A4-1-1/p.1

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please advise whether the figures of 1300 staff and $550 million include the newly regulated hydroelectric facilities. Please advise the number of staff, and dollars, associated with the newly regulated hydroelectric facilities, whether included in those totals or not.

Response

Yes, the 1300 staff and $550 million include the newly regulated hydroelectric facilities. Please refer to Ex L-6.8-2 AMPCO-058 d) i) for the breakdown for the newly regulated hydroelectric facilities.

Three out of the 1300 staff are associated with the newly regulated hydroelectric facilities as outlined in Ex L-6.8-2 AMPCO-058 d) i). A rough estimate of the related cost reduction is about $0.5M.

SEC Interrogatory #007

Ref: A4-1-1/p.2

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide a copy of the Efficiency Review referred to.

Response

Please see Ex L-06.8-17 SEC 116.

SEC Interrogatory #008

Ref: A4-1-1/p.4

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide a brief description of each of the initiatives, included in the "initial list of initiatives" from the business units, that was not included in the final list of initiatives being implemented.

Response

Attached is the initial list of initiatives provided by the business units at the commencement of the Implementation Phase of Business Transformation ("BT") in 2012.

The list of initiatives filed in Ex A4-1-1 Attachment 1 is a subset of this initial list and represents a sample of the larger initiatives that are instrumental to achieving BT. They do not represent all of the initiatives underway.

In addition, the initial listing provided in this response is a point in time view and as a result some of the listed initiatives have been completed, some are still underway, and some were either cancelled or modified upon further investigation into their feasibility.

BU	Initiative Name	Initiative Description
BAS	Management Optimization	This initiative optimizes the management function in the Enterprise Services organization by selecting the final leadership team, with the elimination of management roles, and utilize them on initiatives/projects, leverage attrition opportunites, or enable redeployment to other roles.
BAS	Optimization and Elimination of duplication of Services-Document Management	This initiative optimizes Records and Document Management Services. Business & Administrative Services (BAS) has a clear plan to streamline and optimize Records and Document Management services across OPG throughout 2014 and 2015. The plan outlines an approach from a people, process and technology perspective. Employees will experience quicker turnaround throughout the full end-to-end document process, as manual processes will be streamlined and automated where possible and an online Smart Form will be implemented for faster and easier document submission.
BAS	Service Level Reduction (Library)	The initiative goal is to discontinue the Library Services at 700 University on H17 where possible. Material will be print to record (scanned) and retrieved through the existing Records Service. Clients will no longer be able to use the "library" service to access books, standards, codes, etc. Research service will be discontinued. Reduce/eliminate Journals, Books, Standards, Periodicals and incorporate into the Records Management System as appropriate enabling a self-serve model.
BAS	Print Plant Consolidation	The initiative goal is to achieve consolidation of OPG Print Plants and to centralize Print Services in Durham Region. The deliverable of this initiative is to relocate the current Central Print Shop (located at 700 University) within proximity of primary clients and eliminate 1 Kiosk.
BAS	Optimization and Elimination of duplication of Mail/Administration Services	The initiative goal is to optimize and eliminate duplication of Mail/Administrative Services. Opportunities include: - Reduce Mail Delivery service of every day to every other day (will also reduce # of mail delivery points) - Reduce ratio of dedicated Admin by 30-40% by moving to a 4 Managers sharing 1 Admin model. - Reduce Reception support at sites by enabling a direct link to OPG Call Center (where permitted) - Continue to standardize Office Supplies item list across organization to further reduce costs.
BAS	Administrative Support-LOB Transfer (In/Out)	Administrative Support Transfer into BAS of 85 headcount in 2012; to a transfer out of BAS 85 headcount, back to Line of Business in 2013.
BAS	Management optimization in Facilities	Remove one layer of control in keeping with Business Transformation initiatives by removing the Band G position that currently exists in Nuclear East Facilities.
BAS	Modify Governance	Facilities and Projects will revise and restructure their facilities maintenance program across the province. The new governing program will define building maintenance practices for all OPG facilities with the exception of those carried out inside the Nuclear generating plants. The new program will be created by superseding the existing program N-PROG-MA-0024, which defines maintenance practices for Nuclear facilities outside the Nuclear Protected Areas, with OPG-PROG-0032, a new OPG Corporate-wide facilities maintenance program. The existing maintenance program that applies inside the Nuclear Protected Areas will remain unchanged.
BAS	Staff Reductions through Services optimization	This initiative will reduce the overall headcount in Facilities & Projects through a review of service levels, measuring productivity, modifying work practices to move towards a commercially driven model especially at DNGS and PNGS. Procedures will be streamlined and work tasks revised in the areas of janitorial, grounds maintenance, building maintenance and servicing of TWE equipment.
BAS	Consolidate Hydro-Thermal-Corporate Directors into 1 Position and Reduce 1 Admin	Combine non-nuclear supply chain organizations and streamline management
BAS	Expand the Use of Credit Cards in the Line of Business for purchases < $10,000	Increase use of Credit Cards in the Line of Business for purchases <$10,000 and not Work Management-related at all Hydro and Thermal sites.
BAS	Coal Closure - Warehousing	Based on the assumption that Atikokan, Thunder Bay and Lennox are the only plants in the organization by the end of 2014, we can reduce staff levels in the hydro thermal warehouses.
BAS	Supply Inspection Rationalization	This initiative is focused on process simplification to increase efficiency of the supply inspection processes while fully meeting the applicable standards and regulatory requirements. Main focus areas for process optimization are: - Maximize the use of Engineer, Procure, Construction (EPC) suppliers to perform procurement of project critical spare parts taking credit for the inspection performed by the EPC suppliers and avoid duplication of tasks. - Simplify the inspection process for station transfers to eliminate duplication of tasks.
BAS	Vendor Portal	The Vendor Portal Project builds on the existing, but underutilized Passport capability to transmit and accept electronic data using Electronic Data Interchange (EDI). This value enhancing project will enable the electronic transmission of Nuclear PassPort purchasing and invoice documents between OPG and its vendors using a 3rd party service provider. Specifically, the electronic exchange of documents will include: request for quotations (RFQ), RFQ responses, purchase orders, purchase order acknowledgements, advanced ship notices, invoices and copies of remittance advices for POs generated through the 3rd party service provider. The automation has optimized the process with the electronic submissions/ transmissions where in the past this activity was very manual through faxes and emails.
BAS	Warehouse: Reorganization/ Consolidation of IR/ Logistics/ Transportation between NSC and Corp SC	Amalgamate Investment Recovery/Transportation Sections across Supply Chain that results in delayering and eliminating a Section Manager position and an administrative position.
BAS	Days Based Maintenance Implementation	Nuclear is moving from a 24/7 shift operation to a days-based maintenance operation. Nuclear Supply Chain has been working with the Stations to develop a strategy on type and hours of support/coverage required for a Plant Days Based Maintenance Operation. There will be a reduction in the amount of shifts crews and overall coverage at the plants.
BAS	Increase Core Competency of "Buyer Function"	This initiative is in place to review the core competencies and skill/qualification requirements of the Buyer/Analyst role in Supply Chain. The review will include an analysis of the historical and current job documents across the company, external benchmarking (both nuclear and non-nuclear), and a skills gap assessment of current incumbents. An outcome of this initiative will be a new job document and new training requirements (qualification description).
BAS	Nuclear Warehouse Initiatives - Discontinue Receiving QL-4 items (non-plant equipment)	The goal of this initiative is to eliminate the stocking and maintaining of QL-4 Non-Plant Equipment (e.g. consumables) within Nuclear warehouses / stores and drive towards a "quality parts only" warehouse operation. The opportunities include: - Establishing new commodity agreements for direct procurement of QL-4 consumables. - Implementing end-to-end process transformation using an amazon-like electronic catalogue platform that will support all aspects of the process including Vendor, Finance, Accounts Payable, Customers, etc. The low value work targeted for elimination is that of Warehouse stockkeepers where the consumable items and parts can be handled through direct purchases/vendor managed process outside the warehouse operations.
BAS	Nuclear Warehouse Initiatives - Evaluate IMS Warehouse Operation	This initiative consolidates the Inspection and Mainenance Services warehouse operation with the Pickering warehouse operation resulting in closure of one warehouse facility and the reduction of warehouse staff by centralizing, leveraging skills, and eliminating duplicate work.
BAS	Nuclear Warehouse Initiatives - Evaluate Bruce Waste Warehouse Operation	This initiative closes the Bruce Waste Warehouse operation and supports it from the Pickering Site for receipt and management of quality materials/parts for the Nuclear Waste Operations. All consumbles will now be procured using the new amazon-like electronic catalogue through direct purchases/vendor managed process outside the warehouse operations.
BAS	Nuclear Staging Strategy	The purpose of this initiative is to identify and implement a new process to reduce the current requirements for staging all parts prior to work execution by reducing the current volume of material that is placed in a staging area and not picked up by plant operations. As soon as material is issued and staged, it triggers the reorder processes. Items not picked up are returned to inventory. Reducing the number of parts that are staged will ultimately reduce the churn of reordering parts and reduce the inventory levels.
BAS	IMS Supply Chain Integration	Reorganization and consolidation of Inspection and Maintenance Services Supply Chain with the broader Supply Chain organization in May 2012 which will enable the leveraging of skills and economies of scale eliminating duplication in work effort.
BAS	Safety Environmental Quality Contractor (SEQC) Database Management Rationalization	This is a Health & Safety led initiative which will outsource the service of supplier's health and safety pre-qualification. Along with this outsourcing strategy includes the elimination of an internal database called Safety Environment Quality Contractor (SEQC) which is maintained by OPG Supply Chain.

BU	Initiative Name	Initiative Description
BAS	Supplier Performance Management Rationalization	The use of third party organizations to perform supplier's audits on behalf of OPG is maximized by assigning 40 more audits a year to a third party, in addition to the 45 audits per year currently performed by same third party.
BAS	Optimize real estate services in line with BT constraints	Targetted Real Estate Services' work reduced as a result of: 1) lower leasing and lease management work as OPG downsizes; 2) lower real estate development work as OPG downsizes; 3) limiting the waterfront licensing program to managing and renewing existing licences with no expansion to other river systems; 4) expanding Society staff responsibilities for Hydro Thermal Operations as they shrink; 5) expanding PWU staff responsibilities to include employee relocation services; and 6) prioritizing work with internal customers.
BAS	Optimize Project Oversight Staff for 2013-2014 Project Portfolio	This initiative optimizes the IT Project Oversight function currently performed by internal staff within the CIO. The initiative optimizes the oversight required on projects based on a smaller volume of projects performed annually (project volume has been reduced from over 200 projects in 2009 to under 50 in 2012).
BAS	Optimize Internal Transactional IT Functions	This initiative optimizes the support functions currently performed by internal staff within the CIO that are operational and/or transactional. This initiative optimizes around reduced coal shut down profile and geography synergies and optimizes telecom support by consolidating nuclear roles.
BAS	Dismantle Information Management Transformation Program (IMT) Project Team	The IMT program is being integrated with the overall OPG Business Transformation (BT) initiative and is expected to achieve the planned IMT outcome while supporting critical BT initiatives. This charter documents the shutdown of this temporary organization as the IMT deliverables are completed.
BAS	Plan, Negotiate, and Transition to Next OPG IT Outsource Contract	Prepare for, negotiate, and implement the next IT Outsourcing contract.
FIN	Centralization of staff into a COE for BCS Reviews and Project Reporting	Amalgamate and centralize resources into a Centre of Excellence. Eliminate any duplications and handoffs of Finance reviews of Business Case Summaries. Centralize and streamline major project reporting.
FIN	Centralization of Accounting & Time Reporting into Shared Financial Service Centre	Consolidate BU Accounting activities into a Shared Financial Services Centre , standardize accounting processes to reduce low value activities, and leverage automation of Tempus time distribution.
FIN	Standardize and Centralize Financial Management Reporting	Centralize, standardize and automate the delivery of management reporting. Establish standard suite of reports to minimize ad-hoc reporting.
FIN	Transaction Processing Efficiency Improvements	Centralize and standardize Accounts Receivable and Accounts Payable transaction processing into Shared Financial Services Centre, improvements to upstream procurement processes. Migrate to a single Accounts Payable invoice management system, and leverage automated transaction processing capabilities
FIN	Nuclear Finance Service Delivery Structure	Implement efficiencies in the delivery of Finance support for the Nuclear Business Unit through changes to the Nuclear Finance department structure, leveraging centralized and automated processes and eliminating certain work programs.
FIN	Hydroelectric/Thermal Finance Service Delivery Structure	Implement efficiencies in the delivery of Finance support for the Hydro/Thermal Business Unit through changes to the Hydro/Thermal Finance department structure, leveraging centralized and automated processes and eliminating certain work programs.
FIN	Support Services Finance Delivery Structure	Implement efficiencies in the delivery of Finance support for Corporate Functions through consolidation of department structure from leveraging centralized and automated processes and eliminating certain work programs.
FIN	OPG-Wide Performance / Scorecard Reporting	Implement a common corporate-wide performance reporting process, governance and tool to enable centralization of OPG and BU performance management reporting.
FIN	Streamline Business Planning Process	Streamline Business Planning process to enable efficiency gains in Finance and Business Units. Modify Business Planning process to address findings from consultation with BU and Finance groups (including simplifying standard labour and burden rates). Ensuring performance metrics and targets are tied to strategy and communicated at start of planning process. Enhancing/replacing of Business Planning system
FIN	Improve Efficiency of Taxation Processes	Improve efficiency of income tax, customs, commodity and property tax processes and consolidate all tax activities in one centre of excellence and eliminate lower value work
FIN	Improve Efficiency of External Reporting and Controls	Improve efficiency of external reporting, regulatory accounting and internal controls program by streamline external reporting and regulatory accounting processes, and optimizing support for internal controls over financial reporting program.
FIN	Internal Audit - Assurance Integration and Efficiency	Internal Audit service delivery will become more efficient through the following change initiatives: 1) Development of integrated assurance plan for OPG that includes Nuclear Oversight and other OPG assurance functions. 2) Reliance on management control self-assessment 3) Extend audit cycle from three to four years for selected lower risk business processes.
FIN	Efficiency Improvements to Treasury Operations (Insurance)	Insurance support for Supply Chain to be reduced by introducing standardized insurance terms for contracts
FIN	Efficiency Improvements to Treasury Operations & Fund Management (Shared Back Office)	Centralize Treasury operations in one area by relocating the back office from Fund Management to Treasury.
FIN	Nuclear Oversight Service Delivery Structure	Nuclear Oversight service delivery will become more efficient through the following change initiatives: Consolidation of Nuclear Waste assurance, reducing number of audits with compensatory improved risk analysis protocol and in the field performance assessments, reducing duration of audits by streamlining the process and org. changes. Improved Performance Assessment process and governance in place.
COE	Reduce Market Operations & IRP staff with phase out of coal.	Reduce after the fact analysis of recent market activities which yield recommendations for improved revenue making opportunities going forward. Reduce generation outage management and trading support (eg transmission advice, US market price forecasts, etc)
COE	Market Operations 7x24 Shift Positions	Elimination of one 7x24 shift positions in the Portfolio Management and Trading Control room resulting in three positions from 4.
COE	Phase Out Coal Contracting and Delivery Activities	End coal contracting activities once all coal contracts not required before coal Phase out have been eliminated. End logistical support for coal delivery once all deliveries completed. End studies of coal drawdown. After any unused coal at the site has been disposed of, end all staffing related to coal production in Commercial Operations.
COE	Contracting Expertise	Centralized one-stop shop for all OPG contracting needs, combining Origination Department from Trading, one resource from Fuels and the Commercial Services Division from Nuclear projects. Create a centre of excellence in negotiation of complex power and power by-product contracts which can handle contracts for new and existing capacity (non-nuclear), fuels, market ancillaries, isotopes, heavy water and the Bruce lease.
COE	Scalable Project Management for Major Regulatory Proceedings	Leverage internal and external resources to meet peak work requirements associated with major regulatory proceedings. This would involve adding qualified internal staff onto the hearing teams on a temporary basis and contracting for additional external regulatory consultants and legal resources to contribute meaningfully and promptly during period of high acitivity.
COE	Implement centre-led Environment organization	Initiate full scope centre-led environmental accountabilities: • Advocacy and Governance, • Reporting, • Operational Support, • Project Environmental Assessment Services, • Environmental Specialists. Identify and develop key processes for the approved centre led organization including OPG Environmental Management System and supporting Service Level Agreements with Generating Units and Functions.
COE	Phase Out Analytical and Market Support for Coal	Eliminate coal drawdown studies and programming analysis, market rules training and project management. Reduce market simulation studies, market monitoring and compliance and surveillance activities.
CO	Integrate corporate strategy and capital allocation	Develop a new corporate capital allocation framework/process and integrate with OPG's corporate strategic and business planning processes. The new capital allocation process is to be phased-in over a period of 3 years.
CO	Integrate Business Intelligence in Strategy	Establish an integrated Business Intelligence (BI) collection and sharing network/process; requires re-establishing and/or enhancing new key internal & external BI relationships and translating information into valued/actionable BI
CO	Project Risk Support	Risk management support for project teams to be discontinued with accountability for completion and quality of project risk management plans assigned to project teams. Training to be provided by Project Risk Management to project teams and PMO's.
CO	Major Project Oversight	Internal Audit currently has accountability for Major Project Oversight. The Project Risk Management group has been providing an assessment of the risk management maturity for major projects as well as significant project related risks to the CRO on a quarterly basis. This work will now be undertaken by Internal Audit. ERM will be responsible for strategic risk oversight of destiny projects to input and align with Board reporting.
CO	Strategic Risk Management	Enhance the ERM framework, processes, and tools to put greater focus on OPG's ability to effectively identify, manage, monitor, and report on strategic risks.

BU	Initiative Name	Initiative Description
CO	Credit Risk Counterparty Reduction	Collaborate with Energy Markets Trading and Treasury to optimize the number of counterparties for which Enterprise Risk Management must evaluate. Ensure that a process continues to exist for 'real-time' credit assessment and approval, as required.
CO	Eliminating non-value added reporting/process	Efficiency can be achieved by reducing: Monthly fuel and emission report. As we approach the coal closure timeframe we can start reducing coal related reports, such as monthly fuel and emission report and possibly even fuel hedge report required for MD&A. The frequency and need of all reporting will be reassessed. Work related to adjustment of invoices to be eliminated.
CO	World Class ERM Initiatives	Elimination or scope reduction of initiatives designed to foster a world-class ERM function. Such initiatives to include stress testing and scenario analysis, incorporation of an "All Hazards" approach in risk identification, continuous improvement / benchmarking of ERM processes, and attaining level 4 ot the ISO 31000 standard.
CO	Transform Corporate Centre Brand Management Function	Corporate Brand Management (CBM)is one part of Corporate Relations and Communications which provides expertise, sets guidelines and delivers corporate products related to its area of expertise which inlcudes writing, advertising, corporate citizenship and the use of theinternet and social media. CBM will be further developed through transformation to ensure required capabilities are in place to lead corporate brand while reducing head count through work elimination, productivity levers and synergies such as pooling of resources and streamlining administrative activities.
CO	Transform Corporate Centre Employee Communications	Transform the former HR Employee Communications unit into a Corporate Relations and Communications centre of internal communication expertise with an end state merge of Employee Communications and Brand Management
CO	Transforming the Government/Provincial SR Functions	Provincial Government and Stakeholder Relations has accountability for industry and provincial government relationships (at the working relationship level). Previously two program areas, the provincial government and provincial industry stakeholder function will be combined and adjusted to reflect future OPG priorities. This initiative will consider options to reduce work such as adjusting the level of OPG participation in provincial stakeholder groups and the types of products used to support the day-to-day relationship with the provincial government.
CO	Transforming FN and Métis Relations	The First Nation and Métis Relation (FNMR) group will improve efficiency as work demands evolve by adjusting its focus away from front line work and strengthening its role in providing advice and guidance to operating units and projects as a centre of expertise working in an advisory capacity to the embedded community relations staff and the plant management groups.
CO	Transforming Media Relations, Information and Issues Management	Media Relations and Information is a centre-led function and the end state will see enhanced processes and products. The group will play a pivotal role in providing an environmental scanning process, ensuring an effective information sharing process is in place across the company and proactively and reactively managing media. The work program will be reviewed to identify areas for merging duplicate processes within CRC and across OPG, integrating the daily news and issues with more targeted interpretation of immediate news.
CO	Transform the Stakeholder Relations 'Hydro-Thermal Support Office	The CRC HTO unit will provide centre-led embedded stakeholder-communication service to the Hydro-Thermal plant groups through on-the-ground resources to support leadership teams in key geographical areas as well as provide employee communication guidance. The Director CRC HTO provides a liaison point to HTO for all stakeholder / communication services. Embedded staff will have a dotted line relationship and day-to-day direction working with the leadership team in the field.
CO	Transform CRC - Nuclear Support	The CRC Nuclear unit provides centre-led embedded stakeholder-communication service to Nuclear operations and projects. Functions are centralized and redundancies eliminated in a way that better facilitates the flow of skills and information within the unit and to internal and external stakeholders. Internal communications across the fleet will be centralized, all nuclear projects will be grouped together and an issues/regulatory affairs function will be established. The proposed end-state focuses on priorities while adjusting to attrition and amounts to a rationalization of redundant services and activities. There will be some downward pressure on the level of service external stakeholders and communities are used to but OPG's presence in the community will remain healthy. It will also maintain support for the nuclear option across Ontario. The model also provides the Nuclear groups a one point of contact service provider into the centre of expertise areas of CRC.
CO	Transform CRC Functions Support and Business Transformation	The Functions and BT support group will provide BT "Builder" support to the Corporate Office group to manage the activities that will enable CRC and CO to succeed in Business Transformation. The group will develop a framework to support the Corporate Functions with continued accountability for delivering communications support to the Function areas including People and Culture, Finance and Business and Administrative Services.
HT	Merge Hydro-Thermal business units, Fully Implement Centre-Led Engineering and Reduce engineering involvement in non-engineering work	1. Merge HTO (reduce duplication of effort, streamline governance) 2. Move to Centre-led Engineering (reduce duplication of effort within asset management and engineering risk assessment processes, better utilization of engineering resources across the fleet, reduce engineering involvement in non-engineering activities). Make changes to work processes and practices to enable new Service Delivery group to achieve reductions in engineering resources by reducing administrative burden on engineering staff (rely more on craft skills, reduce engineering involvement in procurement process, reduce engineering involvement in EPSCA, reduce engineering involvement in contract monitoring).
HT	Streamline Engineering/ Asset Management Strategies/Programs	With a centre-led engineering model in place HTO will move to utilize a consistent, standardized asset management process across the entire Hydro/Thermal fleet. This will reduce duplication of effort and avoid sub-optimization at a plant level by maintaining a fleet level view of programs and priorities.
HT	Streamline Plant Processes related to managed systems	ISO registration at the plant level will stop as we have move to a Corporate registration.
HT	Merge Lead Plant Doc and Simplify / Eliminate	Hydro and Thermal have about 110 LP documents. With the merger of the Hydro and Thermal Businesses there will be several (~42) "common" LP documents that can be merged into one or can be eliminated. HTO Lead plant documents will be consolidated under one framework.
LAW	Reduce Environmental Regulatory Enforcement	In order to avoid escalation in enforcement action by the regulators, processes will be changed to ensure Law Division is notified immediately of any environmental incident which could lead to charges, environmental penalties, or orders (e.g., all spills). Law Division will initially communicate this change to Environment staff and then will advise OPG Environmental staff in their dealings with the regulator. Law Division will also liaise with the regulator as needed, in order to ensure complete compliance and mitigation information/arguments are presented to the regulator. This early involvment by Law Division should minimize or avoid subsequent investigations, orders or charges to result in less enforcement action by the regulator.
LAW	Management of Demand for Legal Services	Law Division is transitioning to a new service delivery model, more closely aligned to the business organizations. The Law Division will be structurally and operationally realigned to reflect OPG's business. Lawyers will be imbedded in the senior leadership teams of the businesses they support as partners. Each Business Unit and various functional groups have a lawyer assigned as their business unit counsel. That individual will provide legal advice and also coordinate involvement of other internal and external lawyers as subject matter experts as necessary. Efficiencies will be gained through the business unit counsel better understanding the underlying businesses they support to provide more focused legal and business support.
LAW	Cessation of Document Management	Document Management services currently exist under Business and Administration Services. Law will no longer file executed documents to the Executed Document Centre on behalf of document owner clients. Law will stop retrieval of historical files/records/executed documents for clients from the Corporate Records Department. Efficiencies will be achieved as document owners will be able to both file and retrieve their documents without Law Division playing a middle role.
LAW	Reduce Advice re Nuclear Licensing Matters	Significantly reduce or stop the provision of legal services provided by OPG in-house lawyers with respect to nuclear licensing matters and hearings. A period of intense licensing activity is expected to last over 3 years. Keep internal legal expert for intense 3-year period. During 3 year period transfer knowledge to nuclear regulatory affairs to the extent possible; thereafter, retain scaleable external legal counsel when needed.
LAW	Reduce EA Advice re Nuclear Undertakings	The provision of legal services by in-house OPG lawyers with respect to Nuclear related environmental assessments will be eventually discontinued. While internal legal expertise exists in this area within OPG Law Division, Law Division will continue providing this advice. Thereafter, this advice will be provided on a scaleable basis through external counsel.

BU	Initiative Name	Initiative Description
LAW	Reduce Advice re One-off Discrete Nuclear Regulatory/Safety Issues	Significantly reduce or stop the provision of legal services provided by OPG in-house lawyers relating to Nuclear regulatory and safety issues. Existing internal legal expert who provides advice currently to do so for intense 3-year period of licensing activity. Thereafter, retain scaleable external legal sources.
LAW	Reduce Advice re One-off Discrete Regulatory/Safety Issues	Significantly reduce or stop the provision of OPG in-house legal services and legal training re: issues of nuclear plant security. Existing internal legal expert who provides such advice and training to continue to do so for intense 3-year period of licensing activity. Thereafter, retain scaleable external legal sources.
LAW	Reduce Advice re Freedom Of Information Requests and Appeals	Stop the provision of legal services in-house to OPG with respect to freedom of information requests and appeals. Internal legal expert who currently provides such advice to do so during intense 3-year period of nuclear licensing activity. Thereafter, retain scaleable external legal sources.
LAW	Streamline Owner-Only Legal Advice	OPG governance relating to managing contractors requires Law Division to review every "owner-only" construction project being contemplated within OPG. Over the years, OPG has been performing more projects as "owner-only". Each operating business unit trains certain individuals at OPG to ensure "owner-only" projects are structured to comply with the *Occupational Health and Safety Act* requirements for such projects. For most of such projects, the requirements are straightforward and the trained individuals readily identify the issues and appropriate mitigation strategies. Law Division is not needed to review every owner-only project but should be consulted only where the trained staff identify the need to obtain legal advice. Revise governance and practices to reflect this.
NUC	Create Center Led Engineering Organization	Transfer line authority for Design Engineering, Reactor Safety, Performance & Components Engineering, Fuel Handling, Common Services, Tritium Removal Facility, Nuclear Waste Management Division Engineering , Chemistry-Technical , Procurement Engineering and the Engineering Authority to the Chief Nuclear Engineer. The resultant organization is much simpler and has increased spans of control for managers/supervisors. At the site, the Engineering Authority will be the key driver of the new centralized matrix delivery model
NUC	Create COE for Nuclear Safety analysis	Centralize engineering capability in the area of Nuclear Safety Analysis to provide an efficient and effective service and to establish a centralized expert group.1. Stop work on low value activities such as non reactor safety related reviews 2. Improve efficiency for Darlington Projects support 3. Transfer some work back to Operations; 4. Complete major projects 5. Evaluate Contract out options 6. Realize efficiency gains from Engineering Amalgamation 7. Improve capability in Refurb Nuclear Safety Analysis
NUC	Create COE for Components Engineering	Centralize engineering capability in the areas of Components Engineering and Chemistry to provide an efficient and effective service and to establish a centralized expert group. Reduce work quantity by eliminating lower value work and relying on the accountability model to reduce "chasing" of interfacing groups.
NUC	Leverage Move to EPC Model	Move Project Engineering exclusively to an EPC model (Engineering Procurement and Construction) while retaining sufficient core knowledge and capability to ensure adequate oversight and undertake initial engineering work such as design requirements and conceptual engineering.
NUC	Transform Nuclear Programs and Training to new Organization model	Implement Organizational Change to disband Current Nuclear Programs and Training (NPT) organizational units to new organizational structure (Nuclear Services and Operations and Maintenance Support) Consolidate Site O&M Support and Nuclear Programs, and establish Nuclear O&M Support. Establish Nuclear Services, consolidate new functions (Radiation Protection, Reg Affairs, Strategic Planning and Improvement)
NUC	Create Strategic Planning and Benchmarking Organization	Implement organizational change to combine all Strategic planning & Business Support functions into a new organization under Nuclear Services.
NUC	Implement Centre Led Operating Model (Centralize O&M Support)	Amalgamate Operations Support, Maintenance Support and Performance Improvement Support for the fleet into one group, reporting to the CNOO. Rightsize the Nuclear Peer teams. Transfer staffing function and associated staff to P&C HR function.
NUC	Corrective Action Program	Simplify corrective action program and centralize infrastructure. Increase individual managerial accountability for correcting problems. Improve quality of evaluations and actions. Eliminate low-value process steps. Amalgamate 3 site SCR databases into a single instance. Return accountability for evaluation/action quality to managers as opposed to Corrective Action department (e.g. focus on results, not process) • Reduce organizational appetite for low-level evaluations (e.g. 40% reduction in number of Apparent Cause Evaluations) - shift towards more high-level (i.e. root cause) evolutions and increased trending • Eliminate low value activities • Reassign staff who currently support the process at sites and centrally • Train managers and staff on new accountabilities • Change Corrective Action Review Board, Management Review Meeting focus • Right-size number of evaluators - reduce number of Apparent Cause Evaluators from ~1100 to ~400, reduce number of Root Cause evaluators from ~40 to ~25).
NUC	Automate System and Component Health Reports	Implement Software that exists in the industry that greatly automates System Health and Component Health reporting thus reducing the work load on the System responsible Engineer and the Components Engineer.
NUC	Procurement /Design Engineering Improvements - Stop Material Specification Hand - offs	1.Stop Master Equipmnent List(MEL) and Bill of Material (BOM) hand-offs 2.Stop repeated engineering holds for child Non Identical Component Replacements (NICR) Transfer MEL and BOM update function from Procurement Engineering (PE) to Plant Design and Projects Design.
NUC	Optimize In-House Drawing Modifications	Establish standards and expectations for all EPC modifications to include drawing changes as part of the project and establish supplier capable of doing engineering drawing changes. The intent is that the EPC vendor(s) and contracts need to be established such that all drawing revisions are made as part of the EPC contract. OPG to continue to manage streams of work that impact the plant and work protection including On-Line Wiring (OLW) and Operational flowsheets.
NUC	Reg Affairs: Oversight Role	Change Regulatory Affairs responsibility to an oversight role by driving accountability to the line organizations for compliance with RD-99 reporting in 2013 and preparation of CNSC submissions and prepation of briefing material for public meetings .
NUC	Reg Affairs -Darlington Refurb Consolidation	Merge Darlington Refubishment with Darlington Regulatory Affairs and leverage 10 year Licence Strategy starting in 2015
NUC	Standardize Radiation Protection Equipment and Instrumentation Service Program	Standardize radiation protection equipment and instrumentation and secure a vendor(s) to provide, maintain, calibrate and test required equipment and provide spare parts. Reduce OPG maintenance and calibration of radiation protection equipment and instrumentation.
NUC	Contract RP Instrument Services - Outages	Contract out all outage Radiation Protection services, including incremental dosimetry lab services, ALARA support and Field Technician support.
NUC	Radiation Work Planning/Assessing	Standardize radiation work plans for all routine work. Limit job-specific radiation work planning to high hazard work planning only, and establish templates for high hazard work to streamline their production.
NUC	Optimize Dosimetry Lab and Site Survey Services	Reduce or eliminate Health Physics Laboratory support for the following: - Emergency Bounday TLD - REMP - Dosimetry analyses
NUC	Transfer all Centre-Led Functions from Nuclear Waste Management (NWMD)	Several functions exist within NWMD that can be moved to a Centre-Led organization, similar to all other areas of Nuclear. Move these functions to Centre-Led organizations.
NUC	Maximize efficiencies in Used Fuel Operations and Low & Intermediate Level Waste Operations Management	Reduce staff in NWMD by reviewing efficiencies of the NWMD Business.
NUC	Amalgamate Pickering Work Management	Amalgamate the Work Control and Outage Functions from Pickering A & B into a single Divisional organizational unit.
NUC	Remove volume of planned work from online schedules	Stop scheduling routine, noncomplex work that can be effectively managed at the crew level such as predictive maintenance routines, housekeeping, rounds and non complex system tests. Target 15% reduction in volume of published plan by end of 2012.
NUC	Reduce Handoffs Between SWC/WWL and Schedule Technicians (PCCT) and Model Outages	Eliminate unnecessary duplication between schedulers (SWC and WWL) and technicians when making changes in scheduling applications.
NUC	Create Security & Emergency Services Organization	Consolidate into one organization: Nuclear Security, Corporate Security, Emergency Management, Emergency Preparedness, Site Emergency Response Teams, Fire Protection Programs. Align leadership, vision and organizational direction.

BU	Initiative Name	Initiative Description
NUC	Successful Completion of 3K3 at Pickering.	Pickering is undergoing reliability improvement initiatives including 3K3. This initiative will increase station performance. Once the plans are completed and station performance improvements are realized, engineering staff can be reduced in support and monitoring of the initiative.
NUC	Split NWMD Safety Assessment & Licensing Department and Merge with Nuclear Safety & Licensing Depts.	The absorption of NWMD Safety Assessment personnel into the OPGN Nuclear Safety Division will allow elimination of the NWMD Safety Assessment Section Manager.
NUC	Nuclear Waste Engineering SPMP's/SHR's to Align with Nuclear Governance	NWMD Performance Engineering will be able to gain work efficiencies with respect to the completion and execution of System Performance Monitoring Plans (SPMP) and System Health Reports (SHR) when they complete the transition to OPGN governance.
NUC	Nuclear Waste Engineering Transition to OPGN Conduct of Engineering	NWMD Design Engineering will be able to gain work efficiencies with respect to the ECC (Engineering Change Control) process by transitioning to OPGN governance. In being able to use the "risk based modification" process, it will enable NWMD Design Engineering to apply aspects of the modification process (such as IEE, NICR, etc). Presently, under Waste ECC governance, the use of "risk based" modifications is not allowed.
P&C	Governance and Reengineering Review	Establishment of governance for People and Culture in the areas of Total Rewards, Employee and Labour Relations, Talent Management and Business Change. All existing governance must be reduced and simplified. Current governance is heavily processes driven and needs to be transformed to provide guidelines within which managers can exercise discretion. Current behaviours and processes are as a result of governance. Savings achieved through the transformation of People & Culture are heavily dependent on these governance revisions. (Note: Safety and Wellness Governance is covered under a separate initiative.) (Note2: Training governance is currently out of scope, it will need to form part of an overall Nuclear governance review)
P&C	Process Redesign	Reengineer key processes required to achieve reductions in People & Culture. The People and Culture design team have identified approximately 50 major processes that will enable process efficiencies and reductions in effort required by both People and Culture staff and line management.
P&C	Health & Safety Governance / Management Systems	Develop a corporate level model for health and safety governance and managed system documentation to replace site and business unit specific governance and managed system documentation
P&C	Staffing & Recruiting	Transfer all employees engaged in staffing tasks within Nuclear, Hydro and Thermal into the Talent organization
P&C	Change Management and Org Design	This initiative will leverage the work completed by the Change Management Team and ensure that beyond the BT People and Culture maintains an ongoing model for organization changes to preserve structure integrity and reduce frequency of discrete organizational changes. This will include an on-going enterprise change portfolio management role. This charter also includes the transition of lead accountability for organization changes from Business Partners to Talent Management/Business Change.
P&C	Workforce Planning (WFP)	Establish common tools and methodology to establish workforce planning efforts at the corporate and local levels, ensuring staffing needs are identified and understood, and talent strategies are integrated effectively. The end goal is to have a more focused process that clearly defines roles, accountabitlies and rationale for doing this work and supports quality decision making such as gaps in succession planning. In future all WFP will be based on ONE source of information and is consistent with finance and other IT systems.
P&C	HR Performance Reporting and Analysis	Significant reduction in the HR data fields maintained in HR systems and in the production of information and analysis to support HR programs and OPG business needs. Minimal development of custom reports and required standard reports will be posted in a common repository for use rather than being pushed to users. Elimination of training for HR users on use/access to HR reporting systems (replace with communication on where to find standard reports).
P&C	Outsource Disability Claim Case Management	Third party service provider will provide service in the management of occupational and non-occupational claims with a focus on appropriate treatment and care , transition claims to LTD where required; and pursuing modified/graduated work where appropriate. Service provider will also provide Independent Medical Evaluations (IMEs), WSIB Claims Management, Return to Work Planning.
P&C	Reengineer Occupational Health Surveillance	Occupational health surveillance medical testing and screening (eg. Audiometric, vision, respirator, crane / forklift, etc.) for OPG employees is currently performed by in-house wellness staff. This initiative will distinguish health surveillance tests required to maintain a job qualification (e.g. crane / forklift medicals) and health surveillance tests to satisfy working conditions determined by OPG or by law (e.g. audiometric testing, pressure boundary vision tests, respirator medical screening, etc.).
P&C	Benefits Process	Transfer all benefits administration functions for employees and pensioners to Great-West Life (GWL) including: distributing new employee enrolment packages, verify ineligibility, collecting completed forms for changes in life and employment events, maintaining enrolment data on GWL system (GroupNet). Provide Call Centre for employees and pensioners to respond to both benefits administration and claims inquiries.
P&C	Pension Process	Expand scope of pension administration services provided by Mercer to manage all administration directly with employees on behalf of OPG. This would include distribution of new employee enrolment packages (plan information, all forms), verifying completed forms, termination and retirement packages(event statements), Pension and Beneficiary Changes, family law calculation forms , pension estimates, pension buy back and introduce a Call Centre to respond to employee/pensioner OPG plan specific and administration queries. Leverage self serve online web functionality for Mercer OneView tool.
P&C	Pensioner payroll	Outsource Pensioner payroll to the Trustee – (currently CIBC Mellon), to be funded through the Pension Plan.
P&C	Transfer EPSCA Support from HR function	Transfer support for Electrical Power System Construction Association (EPSCA) from OPG HR to the Contractors and EPSCA. This includes the EPSCA Rep Role performed by HRCs (Travel & board calculation review, mark-up activities; labour requirement communications, interpretation of Collective Agreements & advice; grievances). Also includes the clerical support role performed by Finance & Payroll Reps, Plant Group Clerks &/or HR Admins (security clearances; travel, board & lodging calculations; faxes to Business Agents; setting up mark up meetings; distributing minutes of mark up meetings.).
P&C	Investigate Potential to Outsource Training	Investigate use of external suppliers for delivery of existing training requirements for employees
P&C	Outsource H&S Specialist Services	Currently, OPG has a mixture of service provision for industrial hygiene, ergonomics and safety investigation leadership support. In 2002, Thermal/Hydro moved from internal resources providing this support to external purchased services. Nuclear still has internal staff providing industrial hygiene and ergonomics support, including technologist support, while Thermal/Hydro has been using external services successfully for the past decade. In addition, OPG has a mixture of internal and external team leaders for safety investigations. This project is aimed at aligning the entire corporation with respect to attaining quality external services for industrial hygiene, ergonomics and team leadership for safety investigations, with central smart buyer management to assist in efficiency. Specialized competencies in IH/Ergo and safety investigation services will be retained in the Centre of Excellence (COE) or Shared Services should the critical need arise.
P&C	HR Services Centre	Establish a service centre within People & Culture (P&C) to provide administrative services and advice to employees, managers and pensioners on a broad range of Human Resource (HR) related matters. This includes: • Setting up a contact centre that will respond to general inquiries and provide access to specialized services and administrative support from third party service providers (e.g. pension and benefits administration) and centralized shared services within P&C (e.g. centralized health, safety, pay and staffing functions). • Streamlining administrative processes, centralizing resources (e.g. health and safety, and HR generalist functions), and providing process and program related support within P&C. • Implementing tools to support the monitoring, routing and escalation of requests and inquiries, as well as providing information to employees and pensioners in a more usable and accessible format using web based tools.
P&C	HR Service Centre (Establish High Level process documentation and operating procedures)	Implement and staff a centralized shared services center. The Shared Services Center will feature a call center for general safety and wellness related inquiries from across the corporation, Tier 2 safety and wellness specialists to support more complex inquiries and to provide support to the field service staff across the corporation, and a "back office" support function for the safety and wellness function (e.g. medical records filing, data entry, scheduling, service contract management and quality assurance).
P&C	Eliminate Walk-in Wellness Clinics	Close down the walk-in Wellness clinic offices at all hydro/thermal stations, Nuclear Waste Management sites, Darlington, Pickering, 700 University and elsewhere across the corporation. A self service centre will be established within the company or by a service provider hosted website to provide information on Employee Family Assistance Plan, community resources and other health services.
P&C	Health and Safety Organization Implementation	This initiative is to implement and staff a restructured health and safety organization. COE and Field Services staff will have amalgamated expertise in both safety and wellness. The Shared Service Centre will be a hub for general inquiries and support, with staffing to meet complex support needs through an escalation process as required. The Shared Services Centre will also provide "back office" support to the safety and wellness function. The Field Services staff will maintain presence and site specific support to line management and supervisors on specific field safety needs, and health promotion / return to work support. The scope of this initiative is the implementation of the new organization structure and the staffing processes and transitions to the final target organization structure

BU	Initiative Name	Initiative Description
P&C	Talent Management Initiatives	Reduce talent management services, to a more affordable level, through addressing the following: - Student program and orientation - Campus Grad recruitment - Trades Testing and assessment - Empowered Women's Program - 360 Assessments
P&C	Leadership Development Programs	Consolidate all existing leadership development resources and programming to ensure on-going development efforts are aligned, focused and building the capabilities to support OPG's existing and future organizational and leadership requirements. Identify integration points with Leadership training and dependencies
P&C	Charity Trust	Move the administration of OPG's charity trust to a 3rd party provider
P&C	Consolidation of Joint Union-Management Forums	Streamline participation in joint forums, committees and meetings. Identify and act upon opportunities to reduce the number of forums, eliminate redundancies and low value forums and increase the overall effectiveness and efficiency.
P&C	Improve Labour Relations Capability	Develop appropriate labour relations capability at the executive level, FLM level and within P&C through targeted training.
P&C	Establish Total Rewards COE	Transition the current Compensation Benefits and Pensions units into a strategic Centre Of Excellence (COE). Requires shedding transactional tasks and making appointments to the roles per the COE target structure.
P&C	New Model for HR Business Partners	The embedded HR becomes that of strategic advisor, advocate, team builder and problem solver; not process expert, compliance office and transaction processor. This initiative occurs after the establishment of the HR Services Centre and associated transfer of transactional work, and after completion of ten change initiatives which all result in shedding work from the current business partner population.
P&C	Training - Support & Planning Consolidation	Integrate support & planning functions from Nuclear, Thermal, Hydro and Leadership training organizations. Support includes learning management system administration, learning centre coordination, content production, event planning and scheduling, reporting, measurement, business planning and learning strategy.
P&C	Training - Nuclear Plant Access (Orange Badge)	Challenge the concept of Nuclear Energy Workers (NEW) and the broad facility access rights held by many employees. In some cases, employees who have & maintain access rights to go unescorted into the nuclear plants utilize those rights infrequently or not at all. Maintaining those rights comes with a significant training burden (e.g. Orange badge) and staff would be more effective served being escorted on as-needed basis or provided with JITT. (Require less Orange badge classroom Initial and Requal training. Require less frisker training, require fewer Orange badge tours).
P&C	Review Entry Level Requirements for Training Programs	Increase the recognition of external training and education upon hire and stop re-training qualified new hires. This would also include recognition of training for temp workers.
P&C	Reduction in Training Re-Qualifications	Reduce the frequency of identified requalification's (i.e.. Increase the requalification period) to reduce the number of training deliveries with a focus on classroom delivered training.
P&C	Consolidate Common Training Content	Consolidate content within TIM's, which are common (with perhaps slight variations) separating courses or components of courses that are unique. Reduce frequency of delivery of resulting course(s).
P&C	Training Facilities	To Investigate the possibility for migrating all TDC training activities to PLC and DLC with the intent of closing down the Kipling TDC
P&C	Training - Content, Duration, & Method	One-time and ongoing review of all training courses to validate content, duration appropriateness, and delivery method. This review must have a rigorous challenge process to ensure that all opportunities to reduce are identified while preserving content that meets requirements. Optimize the use of alternative training methodologies including computer based training and computer assisted learning to determine effective delivery medium options. Training programs have evolved over numerous evolutions and caution is necessary to ensure that future impacts are fully understood and evaluated carefully.
P&C	Reduction in Training Qualifications	Reduce excessive qualification linkages to eliminate unnecessary time spent in training by clearly establishing qualification requirements for each work group. Each functional area will establish minimum/maximum thresholds for how many people need to be linked to each qualification for the functional area to accomplish their work programs.

SEC Interrogatory #009

Ref: A4-1-1/p.5

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide details of the number of reductions in FTEs achieved to date, and the portion of those reductions applicable to each of nuclear, previously regulated hydroelectric, and newly regulated hydroelectric.

Response

The number of achieved reductions in FTEs from 2010 - 2012 was approximately 435; 481 in nuclear partially offset by an increase of 3 in previously regulated hydroelectric, and 43 in newly regulated hydroelectric.

The 2013 actual FTEs reductions requested cannot reasonably be assembled and submitted during the interrogatory period. See L-01.0-1 Staff-002.

SEC Interrogatory #010

Ref: A4-1-1/p.5

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please confirm that, prior to 2010, the Applicant did not have a policy to ensure that "internal staff across the company were targeted first to fill vacancies prior to looking externally". If confirmed, please advise what the relevant policy was at that time.

Response

The collective agreements for both the PWU and Society require that internal applicants are selected prior to filling externally.

Prior to 2010, other than the collective agreements, OPG did not have a policy to ensure that internal staff across the company were targeted first to fill vacancies prior to looking externally. Starting in 2010, OPG introduced processes to first evaluate whether there were available staff within the company who could be reassigned to the work, prior to posting vacancies.

SEC Interrogatory #011

Ref: A4-1-1/p.6

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please confirm that the numbers at the bottom of the graph are intended to be the figures represented in the graph. Please explain the apparent anomalies between the graph positions and the numerical information.

Response

OPG confirms that the numbers at the bottom of the graph are the figures represented within the graph.

There are no anomalies between the graph and the corresponding numerical information at the bottom. The graph shows two vertical axes. The left vertical axis shows Total OPG Hires which is shown as the first line in the table at the bottom of the graph and represented as bars within the graph. The right vertical axis shows Total Staff Levels which is shown as the second line in the table at the bottom of the graph and represented as a line within the graph.

SEC Interrogatory #012

Ref: A4-1-1/p.6

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please list the "five new behaviours" referred to, and provide the primary document used to communicate these new behaviours to employees, including the "detailed descriptions" referred to.

Response

The five new behaviours are found on page 5 of the OPG Code of Business Conduct which includes a list and description of the behaviours. The Code of Conduct is the primary document used to communicate these behaviours to employees. A copy is provided as Attachment 1 to this response.

Code of Business Conduct

Safety
Integrity
Excellence
People and Citizenship

Ontario Power Generation is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Ethical business conduct by employees, consultants, contractors, and business partners is a critical component of our operations.

ONTARIO POWER GENERATION

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Introduction

We have all seen examples of companies or individuals who have not acted ethically and the damaging results. Customers question if they should continue doing business with the company and the public loses confidence in what its employees and leaders have to say. When people stop believing in you, the financial consequences may not be immediate, but loss is likely and it can be difficult to recover.

The best way for OPG to avoid these worst case scenarios is to continue working in an ethical way. We need to show Ontario that public power delivered by OPG is the best power. We need Ontarians to keep believing in us. It's not enough to deliver excellent results. We need to achieve those results in an honorable way.

That is why having a Code of Business Conduct (the "Code") is so critical to what we do and who we are at OPG. The Code establishes our values and sets the standard for our business behavior. We expect all employees to understand and follow the Code. It is the only way we can safeguard our reputation as a reliable, ethical company.

The Code is a guideline, it is not a list of commandments or prohibited actions. It's impossible to write a rule book on everything, especially in a large and complex organization like OPG. Instead, the Code and its values clarify what is important to our organization. It is your job to apply it to your daily work and interactions.

OPG's new mission "to be Ontario's low cost generator of choice" has been added to the Code and we will now refer to our four principles as "values." Safety has been added as the leading value, in addition to Integrity and Excellence and "People" has been added to Citizenship as one value. A new section also addresses the behaviours we need to achieve our mission.

There will be situations where the path forward is not clear. If this is the case, seek advice by talking to your supervisor, your Human Resources Consultant and/or the Chief Ethics Officer.

To meet our mission to be Ontario's low cost generator of choice, we need to work together and live by the Code. It will point the way as we strive for success.

Tom Mitchell
President and CEO

Jake Epp
Chairman

Our Values

Safety, Integrity, Excellence, People & Citizenship. These are Ontario Power Generation's ethical values, and are the fundamental truths about OPG that don't change. They clarify what is important in our organization, guide our behaviour and decision-making, and point the way to business conduct that results in successful individuals and a successful company.

Safety

- Demonstrate that safety is fundamental to our business.
- Ensure that all laws and our requirements for a safe and healthy work environment are met.
- Foster a safety culture where continuous learning is embraced and safety is incorporated into day-to-day decision making.
- Take personal responsibility to protect the health and safety of oneself, fellow employees, and the public.

Integrity

- Conduct business lawfully and ethically.
- Avoid conflicts of interest.
- Honour all applicable laws, statutes, regulations, and contractual obligations.
- Protect the confidentiality and sensitivity of information.
- Engage in practices that promote open and fair competition.
- Act fairly, make decisions that are objective, and reflect the just treatment of all.
- Demonstrate uncompromising commitment to OPG's Code of Conduct. Insist on the same standard in others.
- Conduct business in a transparent manner – being open, visible, and publicly accountable.

Excellence

- Commit to and provide excellence in generation.
- Demonstrate excellence in project planning and execution.
- Deliver results in a reliable, efficient and effective manner in support of generation and project excellence.
- Deliver value for money in everything we do.
- Strive for continuous performance improvement.
- Promote excellence in performance where employees excel in their current roles and develop meaningful careers.

People & Citizenship

- Foster the pride of fellow employees in providing an essential service to the Province.
- Treat fellow employees and all others with respect and dignity; value the diversity of cultures and people.
- Conduct business in an environmentally responsible manner.
- Build trust and support the social and cultural fabric of the communities where we work, live and serve.
- Be a socially responsible corporate citizen.

Our Behaviours

Our behaviours are the culture shifts we need to make to be a high performing company and continue to deliver on our mission to be Ontario's low cost electricity generator of choice. These behaviours – Say It, Do It, Simplify It, Think Top and Bottom Line, Integrate and Collaborate, and Tell It as It Is – strengthen and support OPG's Values and are essential to making sustainable change at OPG.

Say It, Do It

Demonstrate personal accountability to deliver results and hold others accountable.

Say It, Do It means setting clear expectations for the results you will deliver, keeping commitments to others, holding others accountable, and taking personal responsibility to solve problems, all with the focus of delivering safe and reliable electricity.

Simplify It

Create the most straight forward path to execution.

Simplify It is about simplifying our work practices, focusing on the result, and challenging anything that is overly complex or doesn't make sense.

Think Top and Bottom Line

Look for ways to improve efficiencies, eliminate waste, maximize generation and make money.

We all have a role to play in eliminating unnecessary time, effort and cost, getting value for money, increasing our generation potential, and ensuring everything we do contributes to the safe and reliable generation of electricity.

Integrate and Collaborate

Break down silos and work together in support of OPG's mission.

Integrate and Collaborate is more than team work: It is building trust and counting on others to deliver, actively communicating with and involving others, understanding and considering others' needs, and working across teams to achieve a common goal.

Tell It as It Is

Demonstrate open and direct communication to everyone with the intention of making things better.

Tell It as It Is means speaking the truth respectfully and without blame, delivering both good and bad news, receiving feedback openly, and addressing conflict directly in order to build relationships and deliver results.

Standards of Business Conduct

This section describes the standards of business conduct that Ontario Power Generation expects from every employee at every level of responsibility. These standards apply to every part of the company and to any wholly owned subsidiary, whether operating domestically or internationally. The standards apply to all Ontario Power Generation employees and are equally applicable to our agents, representatives, consultants, contractors, and business partners.

We honour all applicable laws, statutes, regulations, and contractual obligations.

INTEGRITY

1.0 Conflict of Interest

Definition

Any situation where your personal interest conflicts, appears to conflict, or could potentially conflict, in any way with the interests of Ontario Power Generation (OPG).

Guidelines for Avoiding Conflicts of Interest

There are some broad guidelines for avoiding conflicts of interest:

- Base any business decision on merit and strictly in the best interests of OPG.
- Derive no personal benefit, whether direct or indirect, as a result of making business decisions on behalf of OPG.
- Avoid any situation that may create, or even appear to create, a conflict of interest between your personal interests and those of OPG.
- Do not take part in, or in any way influence, any decision related to OPG that might result in a financial or other advantage for yourself, family members, or friends. Always ensure that these relationships do not impact your ability to make sound, impartial, and objective decisions on behalf of OPG.
- When in doubt, ask your manager or the Chief Ethics Officer.

Declaration of Actual, Perceived, or Potential Conflict of Interest

It is mandatory for employees to declare to their manager and the Chief Ethics Officer any actual, perceived, or potential conflict of interest, in writing, using the form entitled "Declaration of Conflict of Interest or Potential/Perceived Conflict of Interest". There are many reasons employees might need to complete the form. For example, employees might be directly or indirectly involved in an OPG business transaction such as a hiring process, a monetary decision, or a reporting relationship involving someone with whom they have a personal relationship. Please note that these examples are not an exhaustive list.

If in doubt about the situation, complete the Declaration form and give it to your manager.

Upon receipt of this form from their employee, managers should consult with their Human Resources Consultant or the Chief Ethics Officer for assistance in determining the appropriate course of action. This form is available on the Human Resources Code of Business Conduct Intranet site.

1.1 Business Gifts and Hospitality

Accepting gifts and/or hospitality may compromise or appear to compromise your ability to make business decisions that are in the best interest of OPG.

However, on occasion, it may be acceptable to give or receive a business-related gift or hospitality when there is a business benefit to OPG.

Employees must consult their manager for advice on the appropriateness of accepting or offering gifts and/or hospitality.

Gifts having a monetary value such as cash, gift certificates, loans, services, and discounts are not permitted. Gifts such as unsolicited advertising mementos of nominal value would usually be acceptable.

These requirements do not change during traditional gift-giving seasons.

Depending on the circumstances, unacceptable gifts should be returned with thanks and clarification of our policy, or suitably distributed in the community.

For instructions on how to do so, contact your local Human Resources office.

Accepting/giving a gift or hospitality

The term "gifts and hospitality" include such items as meals, beverages, and invitations to social or recreational outings, accommodation, and travel.

Before you offer or accept anything, ask yourself:

- Is the value of the item nominal, e.g., a calendar or pen?

- What will the business benefit be to OPG?
- Is the value and the reason for the gift or hospitality appropriate considering the situation, the people involved, and your role or function within OPG?
- Could it compromise or appear to compromise your ability to make a decision in OPG's best interest?
- Would you be uncomfortable discussing it with your manager, peers, or family?
- Is it compatible with ethical and accepted business practice?

Never offer, ask for, give, or receive:

- Any form of bribe or kickback.
- Any gift, gratuity, entertainment, hospitality, or benefit that may compromise or appear to compromise the ability to make business decisions in the best interest of OPG.

1.2 Outside Business Activities

Serving as a Director or Officer of an Organization

You may not serve as a director or officer of any organization that:

- Supplies goods or services to OPG.
- Buys goods or services from OPG.
- Competes with OPG.

Any exceptions must have approval of the senior executive in your organization.

Investments

If you invest directly or indirectly in an entity that competes with or sells goods and/or services to OPG, you may be in a conflict of interest. This would include those situations when, although you may not directly hold the investment, you have control or direction over the investment. The following rules govern this situation.

Five Percent Limit

In general, you may not own or control, directly or indirectly, ownership interest in an entity of five percent or more. It is your responsibility to notify your manager and Chief Ethics Officer in writing:

1. To obtain approval prior to exceeding the five percent limit.
2. When your ownership interest is less than five percent but could be perceived as a conflict of interest.

Working for Another Organization

Employees have the right to choose how to spend their non-working hours.

You may choose to work part time for another organization in addition to OPG. However,

- You must obtain OPG's prior approval if the work conflicts, appears to conflict, or potentially conflicts with your ability to perform your duties as an OPG employee. In order to obtain approval you must complete the "Declaration of Conflict of Interest Form", describing the conflict, an appearance of conflict, or a potential conflict of interest with the interests of OPG, and forward it to your supervisor.

The following rules apply when you are considering whether to perform work for an organization other than OPG.

You must submit a Conflict of Interest Declaration for approval (see Section 1.0) if you:

- Perform work for a company that competes with OPG.
- Perform work or engage in discussions about employment with a company doing work for OPG or its competitors.
- Perform work that has the potential to assist a competitor of OPG in gaining competitive advantage e.g., acting as a supplier to competitors.
- Perform work for a supplier of OPG or sell products and/or services to OPG.
- Run a business that offers products and services that would compete for business with OPG.
- Use OPG's supplies, facilities, tools, personnel, or intellectual property while working for the other organization.
- Perform work for another organization during OPG's working hours.
- Promote the products or services of the other organization during your OPG working hours.
- Have colleagues or customers from the other organization contact you at OPG.
- Own shares in a company with whom you conduct business with on behalf of OPG.
- Participate in or in any way influence OPG's purchasing or commercial decisions for projects, products and services that relate to a business interest or employment interest that could benefit you directly or indirectly, e.g., a product or service from a company in which you, your spouse or other family member has an interest.

1.3 Relationships with Non-Profit and Professional Organizations

Many of us have an interest in contributing to our communities and to professional organizations. However, this participation must not interfere with the performance of your duties for OPG.

- Your manager must approve any use of OPG time or assets to perform services for a community organization.
- If you act as a spokesperson for an organization, make it clear that you are speaking on behalf of that organization or yourself, and not as a spokesperson or representative of OPG.

1.4 Political Participation

- As a private citizen, you may participate in all levels of political activity in non-working hours provided these activities do not interfere or conflict with your duties and obligations as an employee.
- Your participation must be kept strictly separate from your association with OPG.
- Prior to running as a candidate in a federal or provincial election, you must apply for a leave of absence without pay.
- For municipal government elections, you are required to complete a Conflict of Interest Declaration. See Section 1.0.
- OPG's supplies, facilities, tools, or other business assets such as network assets must not be used to support political activities.

2.0 Sensitive Information

Definition

Sensitive information includes information that is proprietary, technical, business, financial, personal, or requires confidentiality. Sensitive information is owned by, or has been entrusted to, OPG and it must be kept confidential for reasons that include:

1. To preserve OPG's competitive advantage or commercial interests.
2. To comply with all legal, regulatory, or applicable contractual obligations.
3. To safeguard assets.
4. To preserve public safety.
5. To preserve the individual privacy and safety of employees and customers.

Employee Responsibilities

- Know what information must remain in confidence. Ask your manager when in doubt. Refer to the Corporate Records Office Standard that sets out the various security classifications applicable to sensitive information.
- Do not disclose sensitive information, except as required by law, to anyone outside OPG, without prior approval by your manager. This applies even after you have left OPG's employ.
- Within OPG, do not disclose sensitive information to others including your colleagues or other employees unless they need to know the information in order to carry out their OPG accountabilities.
- Protect sensitive information against theft, loss, destruction, unauthorized access/release, or misuse.
- Comply with any applicable insider-trading laws and regulations that govern your use of sensitive information.
- Advise your manager if you are aware of any attempt to obtain or disclose sensitive information by unauthorized means or misuse of such information.
- Follow the Corporate Privacy Program and Procedures when gathering, using, or discussing personal information.
- Comply with corporate policies, standards, and guidelines governing the use of e-mail and information technology systems when storing and transmitting sensitive information.

3.0 Purchasing and Hiring

- Ensure all purchasing and hiring policies, procedures and required processes are followed.
- Ensure access for qualified vendors and applicants to compete for OPG business or employment opportunities.
- Ensure that procurement and hiring processes are conducted in a fair and transparent manner.
- Make purchasing and hiring decisions honestly and with integrity, using such criteria as competitive pricing, quality, quantity, delivery, and service.
- Refuse to make purchasing and hiring decisions based on favouritism, prejudice, preferential treatment, or personal gain.
- Avoid conflict of interest, both real and perceived, during procurement and hiring processes and ensuing contracts and selections.
- Disclose your concerns and refuse involvement in any purchasing or hiring decision that could lead to an actual, perceived or potential conflict of interest. Submit a Declaration of Conflict of Interest.

4.0 Suppliers

- Treat suppliers courteously, fairly, and in a professional manner.
- Inform suppliers about the existence of the Code of Business Conduct and provide access to it.
- Inform suppliers they should contact OPG's Chief Ethics Officer and Security at Head Office (416-592-3146) should they have concerns regarding potentially unethical and/or fraudulent conduct by OPG employees.
- Deal only with suppliers that act with integrity and adhere to high standards of ethical behaviour.
- Inform suppliers they shall not engage in any conduct that would cause OPG or any of its employees to be in breach of any of the obligations set out in the Code of Business Conduct.
- Take appropriate action to address concerns with problem suppliers.
- Take steps to end OPG's relationship with a supplier if it continues to be unsatisfactory.

5.0 Proper Use of Assets

- Protect the company's assets, use them properly, and use them only for OPG business.
- Protect the company's assets from fraud, theft and destruction, e.g., by vandalism or neglect.
- Protect the company's intellectual property such as copyrighted information, trademarks and logos, patents, and trade secrets against loss or infringement, and use them only for OPG business.
- Do not misuse other companies' property entrusted to OPG.
- Only dispose of items having residual value according to the corporate policy governing disposal of assets.
- Theft, fraud, forgery, and willful deceit will not be tolerated and zero tolerance is strictly adhered to.
- While company systems such as e-mail or Internet are intended for business purposes, limited personal use is permissible. Usage must be responsible, limited, and in accordance with OPG's policies, standards, and procedures. As a result of activities performed by the company for network management, security, investigations, or for monitoring in accordance with OPG's policies, standards, and procedures governing usage, privacy cannot be assured.

6.0 Business Expenses

Exercise integrity, prudence, and judgment when you incur and approve business expenses. They must be reasonable and necessary for business or commercial reasons.

Employees submitting expenses for reimbursement from the Company, and managers approving such expenses, must comply with OPG's Business Travel and Expenses Standard.

7.0 Accounting, Finance, and Business Reporting

- Use OPG funds only for lawful and proper purposes in accordance with approved authorities.
- Never establish undisclosed funds or accounts.
- Handle all cash and bank account transactions in a manner that avoids any question of fraud such as bribery, kickbacks, other illegal or improper payments, or any suspicion of impropriety whatsoever.
- Ensure that all OPG documents accurately and clearly represent the relevant facts or true nature of a transaction. These documents include but are not limited to timesheets, sales reports, financial reports, and expense reports.
- Individuals who are aware of conduct or practices that violate OPG financial accounting and reporting values, or who have concerns regarding questionable accounting or auditing matters, are expected to report them to their manager, OPG's Chief Ethics Officer, or Chief Risk Officer.
- Alternatively, OPG has selected EthicsPoint, Inc. to provide a secure third-party reporting system that allows individuals to anonymously report concerns related to questionable accounting or auditing matters. EthicsPoint, Inc. can be reached by calling 1-866-294-8671 or by accessing its website at www.ethicspoint.com.

8.0 Fair Competition

Comply with all laws governing competition including the federal Competition Act and Ontario's Energy Competition Act. For more detail on these laws, please refer to *Competition Legislation Compliance Guidelines for Preventing Anti-Competitive Behaviour*, available through Law and Regulatory Affairs.

9.0 Conducting International Business

OPG's Code of Business Conduct applies to all of the company's operations including those carried out internationally.

10.0 Communications

Ask permission before speaking on behalf of OPG in any public and/or media forum or with a media representative.

- If you do not have prior permission, either stay silent or ensure remarks are identified as personal opinion and not necessarily that of OPG.

Use online and social media within the guidelines and values of the Code of Business Conduct. These media may include:

- The internet;
- Multi-media and social networking sites (e.g., Facebook, Twitter, LinkedIn, YouTube and Yahoo!); and
- Blogs and wikis (e.g., Wikipedia).

Ensure your online posts do not inadvertently link OPG to your participation in political, commercial or other organizational interests.

11.0 Environment

- Meet all legal requirements and any environmental commitments that OPG makes, with the objective of exceeding these legal requirements where it makes business sense.
- Strive to prevent or mitigate adverse effects on the environment with a long-term objective of continual improvement.
- Manage our sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.
- Work with community partners to support regional ecosystems and biodiversity through science-based habitat stewardship.

12.0 Diversity

- Value all individual differences.
- Strive to create a workforce that reflects the diverse populations of the communities in which we operate; in an environment that is respectful and inclusive of all employees.

- Do not discriminate in hiring and employment on grounds prohibited by applicable laws. These include race, ancestry, place of origin, colour, ethnic origin, citizenship, creed (religion), sex, sexual orientation, disability, age, marital status, family status, record of offences, gender identity and gender expression.

13.0 Harassment and Violence Free Workplace

- Treat all employees and persons with whom we do business with dignity and respect.
- Promote an inclusive, healthy and safe workplace that is free from harassment, discrimination, and workplace violence.
- Report any harassment or discrimination in a timely manner to your manager, Human Resources, union representative (if applicable), the Human Rights Office, or the Chief Ethics Officer.
- Report any workplace violence issues immediately to your manager, the Chief Ethics Officer, and Security (416-592-3146).

Do not tolerate:

- Discrimination or harassment on the grounds prohibited by applicable human rights legislation, or any other harassment.
- Personal harassment, including behaviour that demeans, threatens, or humiliates a person or group of people.
- Comments or conduct that ridicule or disparage a group of employees or people with whom we do business even if they are not directed at a particular individual.
- Abusive, threatening, intimidating, or violent acts directed at an employee or anyone else an employee comes in contact with when carrying out his or her responsibilities.

IMPLEMENTATION

14.0 Disclosure, Training and Sign-Off

OPG is determined to be an ethical company. Our ethical values of safety, integrity, excellence, people and citizenship are essential elements of our business success.

- All directors, officers, and employees of OPG must comply with the Disclosure Policy, which is accessible under the OPG Governance section of OPG's Intranet.
- All employees must complete any required training on the Code of Business Conduct. Training on the Code of Business Conduct must be included in the orientation program for new employees.
- Management Group employees in Bands A to H are required to complete an electronic confirmation sign-off statement on an annual basis. This statement will acknowledge that they have read and are in compliance with OPG's Code of Business Conduct.

14.1 Declaration of Actual, Perceived, or Potential Conflict of Interest

Employees must declare to their manager or to the Chief Ethics Officer any actual, perceived, or potential conflict of interest, in writing, using the form entitled "Declaration of Conflict of Interest." Refer to Section 1.0 for more information on this topic.

The manager must ensure that a copy of the form is forwarded to the Chief Ethics Officer, noting the action taken by management to address the issue.

14.2 Reporting Violations or Potential Violations of the Code

Employees who are aware of conduct by others that violates or appears to violate the Code of Business Conduct are obligated to report it to their manager, Human Resources or to the Chief Ethics Officer. **There will be no reprisal against employees for making the report in good faith.**

Managers must immediately report a violation or suspected violation to the Chief Ethics Officer. In circumstances that require an immediate intervention by Security such as workplace violence, theft, and other security-related matters, contact Security at Head Office (416-592-3146). At locations with site/plant security staff, you may contact the local site/plant security group. Security will notify the Chief Ethics Officer on your behalf.

14.3 Confidentiality

The identity of individuals making a report will be kept confidential to the extent permitted by law and the company's ability to address concerns.

14.4 Anonymous Reporting

To report concerns related to financial accounting or auditing, individuals may choose to make anonymous reports through EthicsPoint, Inc. They provide a secure third-party reporting system and can be reached by calling 1-866-294-8671 or by accessing its website at www.ethicspoint.com.

14.5 When the Code Does Not Have the Answer

There may be occasions when the Code of Business Conduct does not have the answer to the ethical question you are facing, or there may be a difficult judgment call to make with respect to the application of the Code. In these cases, consult with your manager, who will either provide guidance or refer you to the relevant policy or to the Chief Ethics Officer.

14.6 Consequences

Those who do not comply with the Code of Business Conduct may be subject to disciplinary actions up to and including dismissal and/or legal action. OPG reserves the right to discipline anyone who knowingly makes a false statement or provides false information.

15.0 Accountabilities

Employees at all levels in the organization are accountable for:

- Understanding their responsibilities under the Code of Business Conduct and for being in compliance with the Code.
- Completing any required training on the Code of Business Conduct.
- Carrying out their responsibilities ethically, with integrity, and treating those with whom they do business with respect and dignity.
- Seeking advice when uncertain about the right ethical decision.
- Declaring all conflicts of interest, perceived conflicts of interest, and potential conflicts of interest, in writing, to their manager as soon as they are known; and reporting conduct that violates or appears to violate the Code of Business Conduct to their manager or Chief Ethics Officer.

Managers at all levels in the organization are accountable for:

- Providing their employees with the necessary tools to understand and comply with their responsibilities under the Code of Business Conduct.
- Ensuring that all of their employees complete any required training on the Code of Business Conduct.
- Ensuring that all of their employees in Bands A to H complete the required confirmation sign-off on an annual basis.
- Reporting suspected violations to the Chief Ethics Officer, as part of due diligence, as soon as they are known.
- Taking appropriate management action to investigate and address known or suspected violations of the Code of Business Conduct.
- Ensuring that their employees complete a written declaration of any potential conflict of interest and addressing any issues in consultation with the Chief Ethics Officer.
- Being concerned, knowledgeable, and reliable counsellors to whom employees can comfortably go for advice.
- Maintaining confidentiality of the identity of the individual raising concerns to the extent permitted by law and the company's ability to address the concern.
- Creating a work environment based on respect that encourages ethical behaviour.

Each **Enterprise Leadership Team member** is accountable for:

- Monitoring compliance with the Code of Business Conduct within their organizations.
- Submitting an annual due diligence report to the Senior Vice President, Law & General Counsel and Chief Ethics Officer that confirms all of their employees have completed all required training on the Code of Business Conduct, employees in Bands A to H have completed the annual confirmation sign-off, and all known violations have been reported to the Chief Ethics Officer.

The **Chief Risk Officer** is accountable for:

- Providing periodic independent assurance to the Board that the control environment and the Code of Business Conduct are operating effectively.

The **Senior Vice President, Law & General Counsel and Chief Ethics Officer** is accountable, on behalf of the President and CEO, for:

- Ensuring that the corporate policy on the Code of Business Conduct is implemented within OPG.
- Preparing a Code of Business Conduct (the "Code") for Board approval.
- Reviewing the Code of Business Conduct on a regular basis to ensure it continues to meet all relevant OPG standards and external business standards.
- Tracking and reporting all violations of the Code of Business Conduct to the President and CEO and the Compensation and Human Resources Committee of the Board of Directors on an annual basis.
- Providing advice and guidance with respect to the provisions of the Code of Business Conduct.
- Ensuring that appropriate management action is taken to investigate and address known or suspected violations.

The **OPG Board of Directors** mandate explicitly acknowledges its role for creating a culture of integrity throughout the organization. The Board has statutory obligations regarding conflict of interest as well as a separate procedure for disclosure. The Board is required to follow both provincial legislative requirements and guidance regarding specific types of conflicts and disclosure in their role as directors in the **OPG Board of Directors' Conflict of Interest Policy and Procedure**.

SEC Interrogatory #013

Ref: A4-1-1/p.7/8

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide, for each of the "organizational changes" listed, the FTEs and budget for those areas immediately before and immediately after the change, and the target FTEs and budget for each by the end of 2014.

Response

a) FTEs and budget for those areas immediately before and immediately after the change:

The FTEs and OM&A budgets for all of OPG, before and after the Business Transformation transfers, are listed in the table below and include the "organizational changes" listed in Ex. A4-1-1 pages 7 - 8. The transfers between areas occurred in 2012 and are therefore, based on the 2012 - 2014 Business Plan.

	OM&A Budget ($M)			Regular FTE Budget		
	Pre BT 2012	BT Transfers	Post BT 2012	Pre BT 2012	BT Transfers	Post BT 2012
Nuclear Operations	1,414	(155)	1,259	6,456	(880)	5,576
Nuclear Projects	270	(54)	216	1,260	(222)	1,038
Hydro Thermal Operations	[redacted]					
Sub Total - Operations						
Commercial Operations & Environment	54	(8)	46	192	3	195
Business & Administrative Services	194	141	335	388	741	1,129
Finance	63	9	72	354	56	410
People & Culture	56	63	119	348	319	667
Corporate Centre	26	42	68	63	122	185
Sub Total – Corporate Support	393	247	640	1,345	1,241	2,586
Total OPG	[redacted]					

b) Target FTEs and budget for each by the end of 2014

The 2014 OM&A targets for each area, as reflected in the approved 2013 - 2015 Business Plan, are found at Ex. A2-2-1, Attachment 2, page 6. The corresponding 2014 headcount targets are found at page 5 of the same attachment. Headcount is used since OPG's business plan targets are not set on an FTE basis.

SEC Interrogatory #014

Ref: A4-1-1/Attach 1

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide, for each of the initiatives listed:

(a) The current status of the initiative;
(b) The amount of incremental spending invested to date to implement the initiative;
(c) The amount of incremental spending included in the Application to implement the initiative;
(d) The savings or other benefits achieved to date;
(e) The savings or other benefits expected to be achieved in 2014 and 2015; and
(f) The savings or other benefits expected to be achieved after 2015.

Response

The table contained in Attachment 1 provides the information requested.

It should be noted that the savings outlined relate to work elimination and not necessarily staff reductions, as the initiatives are aligned with specific work processes and the actual labour dollar savings result from attrition across the company. For instance, for the BAS initiative – *Optimization and Elimination of duplication of Services – Document Management*, we have reduced the work equivalent to 14 staff. However, all 14 of those staff have been reassigned to other work in the company. In contrast, for BAS *Staff Reductions through Services Optimization*, we have reduced the work equivalent to 23 staff and all 23 staff have left the company.

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
Business and Admin Services	Optimization and Elimination of duplication of Services- Document Management	This initiative is on track. To date, the following activities have been achieved: project Executable Plan approved and signed; Change Management Plan approved and signed; and detailed project schedule established and tasks executed as planned.	$0.9M	$0.8M	Reduced work by the equivalent of14 staff. Three Records Storage Vaults have been decommissioned.	Further reduce work by the equivalent of 79 staff.	Initiative ends in 2015
Business and Admin Services	Optimization and Elimination of duplication of Mail/ Administration Services	This initiative is on track. To date, the following activities or efficiencies have been achieved: reduced hours of service for Reception at multiple locations; reduced mail delivery frequency to 2 times a week including the centralization of mail delivery points; a reduction of 34 mail locations was initiated in Q4 2013 and will continue up to Q2 2015; and the analysis was completed for dedicated Administrative support identifying target organizations.	$0	$0	Reduced work by the equivalent of 26 staff.	Further reduce work by the equivalent of 65 staff.	Initiative ends in 2015
Business and Admin Services	Staff Reductions through Services optimization	This initiative is on track. Phase 1 is complete and Phase 2 has been initiated with the tendering of a consulting engagement for a Process Optimization Specialist through the RFQ process. Phase 2 is in the early stages of planning.	$0	$0	Reduced work by the equivalent of 23 staff.	Further reduce work by the equivalent of 21	Initiative ends in 2015

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
Commercial Operations & Environment	Implement centre-led Environment organization	This initiative is on track. The ISO 14001 registration for a single EMS is complete and a plan for further governance simplification is being developed. Transitioning to a centre-led reporting function is being done in phases and includes simplifying the Sustainable Development reporting.	$0	$0	Reduced work by the equivalent of 10 staff. $400k cost avoidance annually for audits as a result of moving to a single EMS.	Further reduce work by the equivalent of 2 staff	Further reduce work by the equivalent of 2 staff
Commercial Operations & Environment	Phase Out Analytical and Market Support for Coal	This initiative is on track. With only Thunder Bay remaining on coal and planning to finish in Q1, there should be no more coal related studies or coal programming analysis required. However, significant work remains on the IESO audit of generation cost guarantee revenues and the bulk of that relates to the coal plants.	$0	$0	Reduced work by the equivalent of 18 staff	Further reduce work by the equivalent of 1 staff	None
Finance	Centralization of Accounting & Time Reporting into Shared Financial Service Centre	This initiative is on track. The design of end state processes is complete and a transition plan for implementation of centralization of accounting has been developed. Work continues on the development and implementation of time reporting system consolidation with automated accounting for labour distribution.	$0	$0	Reduced work by the equivalent of 4 staff	Reduced work by the equivalent of 6 staff	Initiative ends in 2015

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
Finance	Standardize and Centralize Financial Management Reporting	The implementation of the OPG Financial Reporting System (FRS) project is on track to go live on January 1, 2015. Standard cost reports have been designed and will be available to all budget holders starting in 2015.	$4.4M	$2.1M	Reduced work by the equivalent of 14 staff	Further reduce work by the equivalent of 4 staff	Initiative ends in 2015
Finance	Transaction Processing Efficiency Improvements	This initiative is on track. Key changes completed to date include consolidation of the transaction processing functions, streamlining, and optimizing OPG's low value purchases payments process for services invoices under $10,000 and supporting the implementation of a "Vendor Portal". Work continues with Supply Chain on redesigning and optimizing key parts of the "procure-to-pay" process by implementing a set of standard procedures that minimize errors, duplication, and manual effort.	$0.8M	$0.9M	Reduced work by the equivalent of 7 staff	Further reduce work by the equivalent of 10 staff	Initiative ends in 2015

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
Hydro-Thermal	Merge Hydro-Thermal business units, Fully Implement Centre-Led Engineering and Reduce engineering involvement in non-engineering work	This initiative is on track. Merging of Hydro and Thermal Businesses is complete. Implementation of centre-led engineering is in progress, with finalization in 2014, as part of Phase 2 of Business Transformation (on schedule). In 2013, the central Engineering and Technical Services was already working with embedded engineering staff at all stations to engage them in fleet work programs. In addition, working sessions to streamline risk assessment and asset management strategies were conducted.	$0	$0	Reduced work by the equivalent of 8 staff	Further reduce work by the equivalent of 40-50 staff	Further reduce work by the equivalent of 50-60 staff
Nuclear	Create Center Led Engineering Organization	Initiative has been completed and closed for tracking. The transformation to Centre-led Nuclear Engineering is complete, with the exception of the Tritium Removal Facility and site Chemistry – Technical. These will be aligned post redeployment. Stated benefits have been achieved and the business plan is aligned to support the organizational structure.	$0	$0	Reduced work by the equivalent of 25 staff	Further reduce work by the equivalent of 2 staff	None

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
Nuclear	Create Security & Emergency Services Organization	Initiative has been completed and closed for tracking. Additional initiatives have been developed to implement the reductions to the Work Program.	$0	$0	Reduced work by the equivalent of 12 staff. Eliminate duplicate Threat Software $10k savings year over year.	Further reduce work by the equivalent of 22 staff	Further reduce work by the equivalent of 12
Nuclear	Corrective Action Program	Initiative complete. Initiative was able to simplify Corrective Action Program and centralize infrastructure. Increase individual managerial accountability for correcting problems. Improve quality of evaluations and actions. Eliminate low-value process steps. Completed initiative includes: • 30 % reduction in level of effort for the Corrective Action Program since 2011 • Amalgamate 3 site SCR databases into a single instance. Completed August 2013 (savings of $200k/yr)	SCR Database upgrade costs $1.4M	$0	Reduced work by the equivalent of 17 staff. $200k annual savings through consolidation of SCR databases. 30 % reduction in level of effort for the corrective action program since 2011	Further reduce work by the equivalent of 2 staff	None

BU	Initiative Name	a) Current Status of Initiative	b) Amount of incremental spending invested to life to date (Dec 31, 2013)	c) Amount of incremental spending included in the Application (2014 and 2015)	d) Savings or other benefits achieved life to date (Dec 31, 2013)	e) Savings or other benefits in 2014 and 2015	f) Savings or other benefits in 2016
People & Culture	HR Services Centre	In April 2014, there will be an initial launch of the HR Service Centre, at which time employees and managers will start directing all general inquiries to the HR Service Centre. Final implementation readiness activities are in progress, including staff selection, training, communications and operational/IT readiness.	$1.3M	$1.9M	Reduced work by the equivalent of 6 staff	Further reduce work by the equivalent of 35 staff	None
People & Culture	Training - Support & Planning Consolidation	This initiative is on track. Progress has been made on this initiative to March 2014. All training groups have been consolidated into the one centre led Learning and Development organization. Staff Deployment exercises need to be completed to staff the Training Planning and Design department and consolidation of learners to one Learning Management System also needs to be completed. Initiative is on track for completion by June 2015.	$0	$0.5M	Reduced work by the equivalent of 10 staff	Further reduce work by the equivalent of 10 staff	None

SEC Interrogatory #015

Ref: A4-1-1/Attach 1

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

With respect to the individual initiatives:

(a) Please explain more fully "The deliverable of this initiative is to optimize and expand the Administrative support ratio from 2:1 to 3/4:1."

(b) Please explain why the Applicant has 1100 "Apparent Cause Evaluators". Please confirm that those individuals do not have that role as their sole or full-time role in the Company. Please provide more context to help understand why there were so many, and why the dramatic reduction in their numbers is appropriate while maintaining safety and reliability.

(c) Please confirm that only support and planning related to training is being consolidated, and the individual business units will retain their own training functions.

Response

a) The Nuclear Benchmark for the Administrative Support Services function indicates that the ratio of managers supported by administrative clerks could be as high as 4:1 (or 4 managers supported by 1 clerk). This initiative will reduce Administrative Support staff to get to a 3:1 to a 4:1 range.

b) Historically OPG had multiple qualified evaluators in nuclear line organizations for redundancy and flexibility reasons. By reducing the number of qualified individuals, a smaller group of employees are performing a greater number of evaluations. The smaller group of qualified evaluators has allowed OPG to more efficiently focus its training and the quality of the evaluations has been improving as a result. The reduction in the number of qualified evaluators has been facilitated by a reduction in the total number of reports and evaluations since 2011. Individuals do not have the Apparent Cause Evaluator role as their sole/full-time role.

c) Not confirmed. Support and planning related to training is being consolidated along with the design and delivery of all training required across all businesses. Business units will not retain their own training functions, but rather access the centre-led training function.

SEC Interrogatory #016

Ref: A2-1-1-Attach 1/p.23

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

The Applicant says, in its 2012 Annual Report:

> *"The OEB's decision on OPG's application for new regulated prices effective March 1, 2011 established significantly lower regulated prices than submitted by OPG. As such, the regulated prices do not fully reflect the recovery of the costs of the regulated operation and do not allow these operations to earn an appropriate rate of return, thereby negatively impacting OPG's financial performance."*

Please provide full details of all steps taken by the Applicant, in response to the Board's decision in EB-2010-0008, to ensure that its costs were contained within the regulated prices approved by the Board, together with an estimate of the impact of each of those steps taken. Please provide any memoranda, reports, presentations or other documents prepared by or for delivery to the Executive Management Team of the Applicant, analysing or proposing steps to contain costs within the regulated prices approved by the Board in that proceeding.

Response

OPG's ongoing cost control efforts are contained in its Application as discussed in Ex. L-06.3-17 SEC-085.

SEC Interrogatory #017

Ref: F4-3-1/p.23

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

Interrogatory

Please provide OPG's 'Corporate Balanced Scorecard

Response

The 2013 Corporate Balanced Scorecard is provided below.

Corporate 2013 Balanced Scorecard *(Revised Feb 19, 2013)*

Weight	Key Performance Indicators	Threshold	Target	Maximum
10%	**Safety, Environment, Reliability and Code of Conduct** Deliver front-line/core services			
10%	• **AIR:** All Injury rate (Target = CEA Top Quartile)	1.57	0.89	0.36
10%	• Safety focus areas: ○ Improvement in the area of Work Protection Code ○ Continued focus on Situational Awareness • No significant events that impact OPG's reputation	As determined by CEO		
30%	**Financial Performance -** Reduce costs & improve OPG financial health			
7%	EBITDA ($M) (-10%, +15%)	948	**1,053**	1,211
5%	Headcount – Ongoing Operations (+173, -252)	10,550	**10,377**	10,125
15%	Operating OM&A expenditures ($M) (+5%, -10%)	2,735	**2,605**	2,344
3%	Support Services Operating OM&A expenditures ($M) (+5%, -10%)	643.7	613	551.7
35%	**Fleet Operating Performance -** Control costs while delivering front-line/core services			
25%	Nuclear: TW.h	45.99	47.99	48.99
2.5%	Thermal: Start Guarantee rate	85%	94%	97%
7.5%	Hydro: Availability (%)	89.5%	91.6%	93.5%
25%	**Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services			
8% 4% 4% 2% 7%	• OPG Business Transformation Strategy • Niagara Tunnel • Lower Mattagami • Atikokan conversion • Nuclear Refurbishment	Meet project milestones and measures specific to each project – See Attached		
100%				

These measures form the basis on which our overall corporate performance will be assessed but the scores against these measures and overall Corporate score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

2013 Corporate Balanced Scorecard - Project Performance Measures

2012 Corporate Balanced Scorecard – Project Performance Measures (continued) (*Revised March 6, 2013*)	**Threshold**	**Target**	**Maximum**
Business Transformation			
A. Fully Implement the Centre Led Organization (30%)	Both results are at or better than Threshold (Note 1)	Both results are at or better than Target (Note 1)	Both results are at or better than Maximum (Note 1)
1. ELT acceptance of the Deployment Impact Assessment (15%)	May 31	April 30	March 31 plus CEO assessment of cross-BU collaboration
2. ELT acceptance of Deployment Readiness Assessment (15%)	June 30	May 31	April 30 plus CEO assessment of cross-BU collaboration
B. **Transforming the way we work (50%):**			
1. Key transformational initiatives meet the key milestones indicating progress on transformation. (30%) * *Key transformational initiatives identified by Builders' input of 1 or 2 key BT initiatives for each BU*	20 of 30 milestones met as scheduled	25 of 30 milestones met as scheduled	All 30 milestones met as scheduled
2. Business Transformation is embedded in our business practice and culture. a) Business planning appropriately reflects BT initiatives and goals (10%)	CEO Assessment		
b) Transition plan in place to reduce oversight and integration aspects of BT and move key support functions of BT team back to functions and support BU's as business as usual (i.e. change mgmt, HR support) (10%)	Transition Plan in place for 2014 by Dec. 31, 2013	Minimized oversight of BT by Dec. 31, 2013	Transition complete by Dec. 31, 2013
C. **Effectively managing attrition (20%)**			
Target represents the 2013 Business Plan headcount from ongoing operations (excludes DNNP and Refurbishment)	10,550	10,375	10,125

2012 Corporate Balanced Scorecard – Project Performance Measures (continued) (*Revised March 6, 2013*)	**Threshold**	**Target**	**Maximum**
Niagara Tunnel	Both results are at or better than Threshold (Note 1)	Both results are at or better than Target(Note 1)	Both results are at or better than Maximum(Note 1)
A. Forecasted In-Service Date	June 30, 2013	May 15, 2013	March 31, 2013
B. Forecasted Final Cost	$1.55B	$1.5B	$1.45B
[redacted]			
Darlington Refurbishment	All results are at or better than Threshold(Note 1)	All results are at or better than Target(Note 1)	All results are at or better than Maximum(Note 1)
A. Progression of Strategic Contracts (Fuel Handling, Steam Generator, and Turbine Generators) - adherence to schedule (SPI)	0.90	1.00	1.05
B. Containment Filtered Venting System (BCS	Sep 30	Aug 31	July 31

2012 Corporate Balanced Scorecard – Project Performance Measures (continued) (*Revised March 6, 2013*)	**Threshold**	**Target**	**Maximum**
approved and contract for detailed design awarded)			
C. Submission of Global Assessment Report and Integrated Implementation Plan to CNSC	Dec 31	Dec 2	Nov 15
D. Start of Mock-up Construction (date)	July 30	July 15	June 15
E. Scope Definition—All Approve Darlington Scope Requests <= Health of Scope 20 (Note 4)	Dec 31	Dec 2	Nov 15

Notes:

1. For these projects with multiple components, the entire project takes the score of the lowest performing component
   - If any of the tasks are below Threshold, the project does not meet Threshold
   - All tasks must be at or better than target to achieve target. If any task is below target, the project takes the score of the lowest performing task.
   - All tasks must be at or better than maximum to achieve maximum. If any task is below maximum, the project takes the score of the lowest performing task.

2. Threshold achievement for Niagara and Atikokan will be based on the October month end EPC contractor forecasts

3. Includes formwork, rebar and concrete pour, but does not include shoring removal.

4. Exceptions (approved by the EVP Nuclear Projects) are allowed for the following: Scope resulting from planned inspections or analysis scheduled during or after 2013, i.e. scope resulting from scheduled inspections in the 2015 VBO outage. Any new scope approved by: The Darlington Refurbishment Scope Review Board during or after 2013. Any new scope resulting from the CNSC's review and approval of the EA or ISR. "Approved" Darlington Scope Requests require approval by the Darlington Refurbishment Scope Review Board.
   - The following are the Health of Scope definitions (note the lower the score, the scope is better defined):
     - 90 Scope will not be executed in Nuclear Refurbishment, DSR will be removed pending PSRB approval
     - 60 Pure engineering or procedures with no likely field work (i.e. provide CNSC with reports, update procedures, etc)

- 50 Assessment is required to build a report for analysis
- 40 Analyze the completed report to determine actions / path forward
- 30 Actions to implement selected, may be a component strategy across many systems
- 20 Work is known at the system or project level but not component
- 10 Work is known at the component / MEL level
- 5 DSR is adequately known such that it is ready for Work Order to be input on all Units
- 4 All Work Orders input for DSR on all applicable Units or all work completed for DSR

[redacted]

Board Staff Interrogatory #005

Ref: Exh A2-1-1 Attachment 1, Attachment 2b

Issue Number: 1.3
Issue:
Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

The OEB has approved OPG's request to use US GAAP for ratemaking purposes effective on January 1, 2012.

a) Please summarize US GAAP accounting requirements that have been included in this application that result in different accounting treatments from OPG's last payment order proceeding under Canadian GAAP.
b) Please identify changes arising from US GAAP reporting for assets, liabilities, revenues, expenses, gains and losses.
c) Please indicate if OPG adopted any new US GAAP accounting standards or requirements since OPG's adoption of US GAAP in 2012, and if so, please identify the associated financial impacts.

Response

a) As discussed in Ex. A2-1-1, section 4.0, there are three differences between US GAAP and Canadian GAAP that impact OPG's regulatory accounting and that are reflected in the current application. These relate to long-term disability ("LTD") plan costs, Bruce lease revenue, and Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits ("ITCs"). These differences were also explained in detail in EB-2012-0002, Ex. A3-1-2.

   The above differences are also discussed, as applicable, in OPG's 2012 audited consolidated financial statements and the 2012 audited financial statements of OPG's prescribed facilities.

   Specifically, Note 22 to the 2012 audited consolidated financial statements discusses the difference in accounting treatment for LTD plan costs under the heading *Pension and OPEB* on p. 146 of Ex. A2-1-1, Attachment 1 and for Bruce lease revenues under the heading *Deferred Revenue* on p. 147. Note 18 to the 2012 audited consolidated financial statements for the prescribed facilities discusses the LTD plan costs under the heading *Pension and OPEB* on pp. 64-65 of Ex. A2-1-1, Attachment 2b and the SR&ED ITCs under the heading *Income Taxes* at p. 65.

b) The requested impacts on the regulated operations are presented and discussed in Note 18 to the 2012 audited consolidated financial statements of OPG's prescribed facilities at Ex. A2-1-1, Attachment 2b.

c) OPG has not adopted any new US GAAP accounting standards or requirements that have had any financial impact on the regulated business since the adoption of US GAAP effective January 1, 2012.

The only new US GAAP accounting requirements adopted by OPG relate to disclosure requirements. A description of the requirements adopted for 2012 is found in Note 3 to each of OPG's 2012 audited consolidated financial statements (Ex. A2-1-1, Attachment 1, p. 93) and 2012 audited financial statements of OPG's prescribed facilities (Ex. A2-1-1, Attachment 2b, p. 17). A description of the disclosure requirements adopted for 2013 is found in Note 2 on p. 9 of OPG's interim consolidated financial statements for the nine months ended September 30, 2013 (Ex. A2-1-1, Attachment 5).

Board Staff Interrogatory #006

Ref: Exh A2-1-1 Attachment 1, Attachment 2b

Issue Number: 1.3
Issue:
Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

Under US GAAP, Accounting Standard Codification 980 ("ASC 980") sets out rate-regulated financial reporting requirements for rate-regulated entities. The accounting requirements under ASC 980 are compulsory and not optional for rate-regulated entities.

a) Please explain how the ratemaking actions specific to OPG and the general regulatory accounting requirements of the Board have been incorporated in OPG's financial reporting in its audited financial statements effective January 1, 2012.
b) Under ASC 980, please confirm OPG's understanding that the rate regulator has the authority to set and approve regulatory accounting policies which must then be included in the financial statements of the rate-regulated entity. If not, please explain.
c) Please confirm that a rate-regulated entity regulated by the Board should first seek approval of any changes to its regulatory accounting policies from the Board through a rate order or an accounting order prior to making these changes? If not, please explain.

Response

a) The impacts of regulation by the OEB are reflected in OPG's consolidated financial statements as outlined below.

   i. General -- OPG's overall accounting policy for rate-regulated operations is discussed in Note 3 to the 2012 audited consolidated financial statements (Ex. A2-1-1, Attachment 1, page 86) and the 2012 audited financial statements for the prescribed facilities (Ex. A2-1-1, Attachment 2b, page 11), under the heading *Rate Regulated Accounting.* OPG's consolidated financial statements and the financial statements for the prescribed facilities reflect applicable disclosure requirements related to rate regulation as stipulated in Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations* ("ASC 980").

   ii. Regulatory Asset and Liabilities for Deferral and Variance Accounts - The details of the regulatory assets and liabilities for deferral and variance accounts are found in Note 5 to each of OPG's 2012 audited consolidated financial statements (Ex. A2-1-1, Attachment 1, page 96) and the 2012 audited financial statements for OPG's prescribed facilities (Ex. A2-1-1, Attachment 2b, page 20).

iii. Other Regulatory Assets – A description of the regulatory asset for deferred income taxes is found in Note 5 to each of OPG's 2012 audited consolidated financial statements (Ex. A2-1-1, Attachment 1, page 100) and the 2012 audited financial statements for OPG's prescribed facilities (Ex. A2-1-1, Attachment 2b, page 25), under the heading *Deferred Income Taxes*.

A description of the pension and OPEB regulatory asset is found under the heading *Pension and Other Post Employment Benefits* in Note 3 (Ex. A2-1-1, Attachment 1, pp. 91 to 92 and Attachment 2b, pp. 15 - 16) and under the heading *Pension and OPEB Regulatory Asset* in Note 5 (Ex. A2-1-1, Attachment 1 page 100 and Attachment 2b, page 24) to each of the above financial statements. Further information on the pension and OPEB regulatory asset is also found in USGAAP transition Note 18 and Note 22 to the two above financial statements, respectively (Ex. A2-1-1, Attachment 1, pp. 146 - 147 and Attachment 2b, pp. 64 - 65).

iv. Revenue – OPG's generation revenue for the regulated assets reported in the statement of income reflects regulated payment amounts approved by the OEB.

b) OPG confirms that the OEB has the authority to set and approve regulatory accounting policies for the purposes of setting payment amounts and reporting to the OEB. However, the OEB does not have authority to set financial accounting requirements, as noted in the EB-2008-0408 Report of the Board (page 4), nor does ASC 980 mandate the inclusion of regulatory accounting policies in the financial statements of a rate-regulated entity.

Effective January 1, 2012, OPG is required to prepare its financial statements in accordance with USGAAP pursuant to *Ontario Regulation 395/11* under the *Financial Administration Act* (Ontario). Where applicable under USGAAP, OPG must therefore be in compliance with ASC 980. ASC 980 sets out specific requirements in accounting for the economic effects of rate regulation (i.e., economic benefits or obligations that are required to be obtained from, or settled with, the ratepayers as a result of regulation). ASC 980 does not require OPG to reflect the regulatory accounting policies prescribed by the regulator in its financial statements. In fact, reflecting such policies, other than as part of accounting for the economic effects of regulation in accordance with the specific guidance in ASC 980, would not be in compliance with ASC 980 and therefore USGAAP.[1]

(c) OPG typically gets approval of its regulatory accounting for ratemaking purposes through the approval of its proposed payment amounts or riders. Depending on the circumstances, approval of regulatory accounting for ratemaking purposes is most efficiently done through a rate application, an application to clear deferral and variance account balances or through an accounting order application.

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[1] For example, paragraphs ASC 980-10-05-7 and ASC 980-10-05-8 discuss the relationship between financial accounting in accordance with US GAAP and rate-making treatments prescribed by an economic regulator.

CCC Interrogatory #007

Ref: Ex. N1.T1/S1/p. 2

Issue Number: 1.3
Issue: Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

In the update provided on December 6, 2013, OPG has identified an amount of $33 million that reflects an increase in the 2014-2015 revenue requirement as a result of the new business plan. OPG is not seeking to recover those amounts in the revised payment amounts and riders. How will those amounts be recovered?

Response

OPG is not planning to seek recovery of these amounts.

CCC Interrogatory #008

Ref: Ex. N1.T1/S1/p. 22

Issue Number: 1.3
Issue: Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

What is the overall bill impact on a typical customer's monthly bill that relates specifically to the inclusion of the newly regulated hydroelectric facilities?

Response

The overall bill impact on a typical customer's monthly bill that relates specifically to the inclusion of the newly regulated hydroelectric facilities is estimated to be $0.94/month.

CCC Interrogatory #009

Ref: Ex. A2/T2/S1/p. 2

Issue Number: 1.3
Issue: Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

The evidence states that, “OPG recognizes the impact of its operations on ratepayers and takes into consideration such impacts when setting its business planning targets and guidelines.” Please provide a detailed explanation as to how OPG considers the impacts on ratepayers when setting targets. To what extent has a consideration of ratepayer impacts affected this application?

Response

Please refer to Ex. L-1.2-2 AMPCO-004 d.

SEC Interrogatory #018

Ref: A2-1-1/p.4

Issue Number: 1.3
Issue: Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

Please provide a table showing the calculation of the base rent revenue, and the Bruce Lease Net Revenues, annually, from the beginning of the lease until the end of 2015, as well as any associated tax impacts, in each of CGAAP and USGAAP. Please confirm that the effect of the change to USGAAP is to decrease revenues recognized on or after April 1, 2008, and increase revenues recognized before April 1, 2008. Please provide details of the accounting entries used to reflect that adjustment at the time of implementation of USGAAP.

Response

The requested amounts are provided in Chart 1 for the period from 2008, the year when OPG became regulated by the OEB and Bruce Lease net revenues became required to be calculated on a stand-alone basis using GAAP for unregulated entities. The requested calculation of Bruce Lease base rent revenues under CGAAP and US GAAP for the 2008 - 2015 period is presented in Charts 2 and 3, respectively with evidence references provided where available. The US GAAP amounts are retrospectively re-calculated amounts.

Chart 1 – Comparison of Bruce Lease Net Revenues

$M	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
CGAAP								
Base Rent Revenue[1]	72.7	40.9	40.9	40.9	40.9	40.9	40.9	40.9
Future Income Tax Expense Associated with Base Rent Revenue[2]	22.9	12.7	11.9	10.8	10.2	10.2	10.2	10.2
Bruce Lease Net Revenues[3]	(213.2)	37.4	177.6	68.2	(117.7)	7.9	41.3	42.2
USGAAP								
Base Rent Revenue[4]	69.5	38.7	38.7	38.7	38.7	38.7	38.7	38.7
Deferred Income Tax Expense Associated with Base Rent Revenue[2]	21.9	12.0	11.2	10.3	9.7	9.7	9.7	9.7
Bruce Lease Net Revenues[5]	(215.4)	35.9	176.0	66.5	(119.4)	6.1	39.7	40.6

[1] Amounts for 2008 to 2012 from EB-2012-0002 Ex. L-1-7 SEC-04, Table 1, line 5. Amount for 2008 is the sum of 2008 amounts in line 7 from Chart 2. Annual amounts for 2009-2015 as calculated in Chart 2.
[2] Base rent revenue amount x tax rate (2008- 31.5%, 2009- 31.0%, 2010- 29.0%, 2011- 26.5%, 2012 to 2015- 25.0%)
[3] Amounts for 2008 to 2012 from EB-2012-0002 Ex. L-1-7 SEC-04, Table 1, line 22. Amount for 2013 from Ex. L-9.1-17 SEC-132, Attachment 1, Table 13, line 1.
[4] Amounts for 2011-2012 and 2014-2015 from Ex. G2-2-1, Table 2, line 5. Amount for 2013 from Ex. L-1-1 Staff-2, Attachment 1, Table 36, line 5. Amount for 2008 is the sum of 2008 amounts in line 7 from Chart 3. Annual amounts for 2009-2015 are as calculated in Chart 3.
[5] Amounts for 2011-2012 and 2014-2015 from Ex. G2-2-1, Table 1, line 9. Amount for 2013 from Ex. L-1-1 Staff-2, Attachment 1, Table 36, line 31.

Chart 2 – Calculation of CGAAP Bruce Lease Base Rent Revenues ($M)[1]

		Jan 1 to Mar 31 2008	Apr 1 to Oct 31 2008	Nov 1 to Dec 31 2008	Annual 2009-2015
1	Cash Basis Rent Revenue [2]	18.0	n/a	n/a	n/a
2	Total Rent per Lease Agreement Over Lease Term		881.0	1,159.0	
3	Lease Term (months)[3]		129	338	
4	Number of Months in the Period	n/a	7	2	12
5	Straight Line Rent Revenue *(line 2 / line 3) x line 4*		47.8	6.9	41.1
6	Pre-Nov 2008 Deferred Revenue Adj. *(line 11)*		-	(0.0)	(0.2)
7	**Total Base Rent Lease Revenue** *(lines 1 + 4 + 5)*	**18.0**	**47.8**	**6.9**	**40.9**
Pre-November 2008 Deferred Revenue Adjustment Calculation:					
8	Rent per Lease Agreement Jan 1 - Oct 31, 2008			42.0	
9	Straight Line Revenue Jan 1 - Oct 31, 2008 *(line 5)*			47.8	
10	Deferred Revenue at Oct 31 2008 *(line 8 - line 9)*	n/a		(5.8)	
11	Deferred Revenue Adj. Effective Nov 1, 2008 *(line 10 / line 3) x line 4*			(0.0)	(0.2)

[1] Numbers may not calculate due to rounding

[2] As explained in EB-2012-0002 Ex. L-6-1 Staff-37 and EB-2010-0008 Ex. G2-2-1, section 4.1.1, OPG accounted for Bruce Lease base rent revenues on a cash basis prior to April 1, 2008, the effective date of payment amounts that reflected this revenue on a straight-line basis pursuant to the OEB's EB-2007-0905 Decision with Reasons.

[3] As explained in EB-2010-0008, Ex. G2-2-1, section 4.1.1, the pre-November 2008 accounting lease term was determined to be to December 2018 in accordance with GAAP. As noted in Ex. G2-2-1 section 4.1.1 and explained further in EB-2010-0008 Ex. G2-2-1, section 4.1.1 and EB-2012-0002 Ex. L-1-1 Staff-06, in late 2008 (i.e., effective November 1, 2008), the accounting lease term was extended to December 2036 in accordance with GAAP.

Chart 3 – Calculation of US GAAP Bruce Lease Base Rent Revenues ($M)[a]

		Jan 1 to Mar 31 2008	Apr 1 to Oct 31 2008	Nov 1 to Dec 31 2008	Annual 2009-2015
1	Cash Basis Rent Revenue	n/a	n/a	n/a	n/a
2	Total Rent per Lease Agreement Over Lease Term	1,362.0	1,362.0	1,159.0	
3	Lease Term (months)[c]	216	216	338	
4	Number of Months in the Period	3	7	2	12
5	Straight Line Rent Revenue *(line 2 / line 3) x line 4*	18.9	44.1	6.9	41.1
6	Pre-Nov 2008 Deferred Revenue Adj. *(line 11)*	n/a		(0.4)	(2.5)
7	**Total Base Rent Lease Revenue** *(lines 1 + 4+ 5)*	**18.9**	**44.1**	**6.5**	**38.7**
Pre-November 2008 Deferred Revenue Adjustment Calculation:					
8	Rent per Lease Agreement – 2001 to Oct 31, 2008	n/a		523.0	
9	Straight Line Rent Revenue – 2001 to Oct 31, 2008			592.7	
10	Deferred Revenue at Oct 31 2008 *(line 8 - line 9)*			(69.7)	
11	Deferred Revenue Adj. Effective Nov 1, 2008 *(line 10 / line 3) x line 4*			(0.4)	(2.5)

OPG confirms that, as previously noted in EB-2012-0002, Ex. L-6-1 Staff-37, the retrospectively recalculated USGAAP base rent revenue amounts, net of income taxes, are approximately $1.6M per year lower compared to amounts OPG recognized since April 1, 2008 following the OEB's direction in EB-2007-0905. OPG also confirms that the total base rent revenue recognized by OPG prior to April 1, 2008 in its consolidated financial statements prepared under CGAAP is lower than what it would have been under USGAAP.

As noted at Ex. L-1.3-7 SEC-019, Attachment 1, page 2, the following pre-tax journal entry was recorded by OPG as part of the opening USGAAP balance sheet at January 1, 2011 in relation to the difference in accounting for Bruce Lease base rent revenues from the inception of the lease in 2001:

Dr. Deferred Revenue Liability	$59M	
Cr Retained Earnings		$59M

SEC Interrogatory #019

Ref: A2-1-1/p.4

Issue Number: 1.3
Issue: Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

Interrogatory

Please indicate where, in EB-2011-0432, the Applicant disclosed to the Board that the transition to USGAAP would have an impact on accounting for Bruce Lease Net Revenues. If this was not disclosed in that Application, please indicate when the Applicant first disclosed this impact to the Board, and provide a copy of that disclosure. Please provide details of all analysis, study, or other work done by or on behalf of the Applicant prior to March 2, 2012 relating to the impact of the transition to USGAAP on Bruce Lease Net Revenues, and provide copies of any memoranda or other documentation relating to that work, whether the documentation is dated before or after March 2, 2012.

Response

The impact of the USGAAP transition on Bruce Lease net revenues was not discussed in EB-2011-0432.

However, OPG comprehensively discussed the impact of adoption of USGAAP on Bruce Lease net revenues in EB-2012-0002 as part of its request to adopt USGAAP for regulatory purposes and recover December 31, 2012 balances in deferral and variance accounts, including the Impact for USGAAP Deferral Account. Specifically, OPG's evidence at EB-2012-0002, Ex. A3-1-2, section 4.2.2 (page 6), was as follows:

> 4.2.2 Bruce Lease Base Rent Revenue
> USGAAP requires the amount of base rent revenue to be recognized on a straight-line basis from the start of the Bruce Lease in 2001. Under CGAAP, the amount of rent revenue recognized is calculated on a straight-line basis effective April 1, 2008 following the OEB's direction that "Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses" (EB-2007-0905, page 110). The earlier effective date for the purposes of the straight-line calculation under USGAAP results in a lower amount of revenue being recognized over the remaining expected lease term.
>
> The consequent reduction in base rent revenue of \$2.2M per year starting in 2011 results in a corresponding reduction in deferred taxes of \$0.6M, so the overall impact is a \$1.6M annual reduction in Bruce Lease net revenues. This change will increase the revenue requirement in OPG's next application for new

nuclear payment amounts based on USGAAP, but has no impact on the deferral and variance account balances.

OPG responded to several interrogatories regarding the impact of adoption of USGAAP on Bruce Lease net revenues, including Ex. L-1-7 SEC-04 and Ex. L-6-1 Staff-37. In addition, Note 22 to the 2012 audited consolidated financial statements discusses the difference in accounting treatment in Ex. A2-1-1, Attachment 1, page 147 under the heading *Deferred Revenue*.

Attachment 1 is an accounting memorandum, *US GAAP Conversion Memo – Bruce Power Lease*[1], relating to the impact of OPG's transition to USGAAP on accounting for Bruce Lease base rent revenue, which, with the exception of consequential deferred income tax impacts, is the only impact on Bruce Lease Net Revenues of transition to US GAAPhe details of OPG's analysis of the impact of USGAAP transition on Bruce Lease base rent revenue are found in the above memorandum and related spreadsheets (Attachment 2). The calculation of base rent revenue under US GAAP is provided above.

[1] Although Attachment 1 is marked "DRAFT" and indicates that it is a "Draft for Discussion Purposes", no subsequent changes were made and this became the final document.

Bruce Power Lease

US GAAP Conversion Memo

Document change control status	
OPG Owner	Melissa Yuen
OPG Working group	Melissa Yuen / Terry Dereski
Reviewer	Alec Cheng
Approval	Joanne Barradas
Concurrence	E&Y

Topic Name: Bruce Power Lease
Topic Owner: Melissa Yuen
Priority: Medium

1. Executive Summary

Ontario Power Generation ("OPG") will be adopting United States generally accepted accounting principles ("US GAAP") for the year beginning 2012 (with a 2011 comparative period). This memo addresses the significant difference areas between US GAAP and Canadian generally accepted accounting principles ("Canadian GAAP") in the Bruce Power Lease.

OPG will adopt US GAAP guidance on the basis that it has followed US GAAP from day one as there is no first time adoption of US GAAP standard (i.e. no exceptions or exemptions from first time adoption).

Please refer to US GAAP conversion memo "Leasing" for the remaining leasing considerations relevant to OPG.

Key GAAP differences analysed:

A. Lease classification

The concept contained in ASC 840-10-25-42 (b) is similar to that contained within CICA 3065.07(c). Similarly, US GAAP states that a lease is operating in nature if either condition in ASC 840-10-25-42 is not met. Bruce lease continues to be classified as an operating lease under US GAAP.

B. Straight lining of lease payments

OPG must straight line minimum lease payments over the term of the lease from the inception of the lease. The result is an increase on its balance sheet with the corresponding offset to retained earnings.

The journal entries required on transition would be as follows:

Dr. Deferred Revenues	$59m	
Cr. Retained Earnings		$59m

The entries required during 2011 as a result of straight lining the lease payments are as follows:

Dr. Revenue	$39m	
Cr. Deferred Revenues		$39m

2. Scope and Background

This memo addresses Bruce Power lease arrangement and considerations relevant to the conversion to US GAAP from existing Canadian GAAP guidance.

The Bruce Power Lease is between OPG ("Lessor") and Bruce Power ("Lessee") for the Bruce nuclear generating stations. The agreement is comprised of a master agreement for the lease of the nuclear generating site as well as several ancillary agreements for services provided at the site by OPG.

The following are the key terms in the lease agreement:

Initial Lease Payments

Bruce Power was required to make an up-front payment at the inception of the lease. OPG deferred $229 million of the initial lease payment and is currently amortizing the amount over the initial lease term (until 2018).

Base Rent

OPG is subject to an operating lease agreement with Bruce Power L.P. (lessee) that specifies scheduled Base Rent increases starting in 2001 and ending 2018, for the leased premises. The Base Rent was $62 million in 2001 and escalates to $92 million in 2018.

If the lease is extended beyond 2018, the Base Rent will be $32 million for 2019, and $32 million every two years going forward commencing 2020 up to 2036.

Since November 2008, OPG recognizes the Base Rent on a straight line basis over to 2036 consistent with OPG's best estimate as of November 2008 when the lease was last substantially modified. Prior to November 2008 but before March 2008, the lease term of 2018 was used to calculate lease revenues. Prior to April 2008, OPG recognizes Bruce Lease revenues as stipulated in the lease agreement.

Supplemental Rent (As amended on January 1, 2002)

Supplemental rent is based on a Bruce nuclear generating Unit being operational at any time during future calendar years.

The annual supplemental rent for each Bruce A and Bruce B nuclear generating Units which is operational during the calendar year is $25.5 million multiplied by the consumer price index (CPI) adjustment, except where the Hourly Ontario Energy Price (HOEP) for the calendar year is less than $30.00 per MWh, in which case the annual supplemental rent per unit is reduced to $12 million. The CPI adjustment for any year is the CPI (Ontario) for the month of January in the applicable calendar year divided by the CPI for January 2002.

Further amended in an amendment dated October 2005, the supplemental rent for Refurbished Bruce A Unit would be approximately $5.6 million per unit given the unit is operational at any time during the future calendar years.

The supplemental rents are considered contingent in nature and hence are recorded monthly as stipulated.

<u>Penalty for not Exercising Options (November 2008 amendment)</u>

OPG and Bruce Power entered into a settlement agreement in November 2008, which entitles OPG to a pre-determined one-time payment if a triggering event occurs. A triggering event is defined as a material event of default or failure by Bruce Power to exercise its options to renew the lease such that the term of the lease will expire prior to June 30, 2028.

3. Relevant Guidance

- FASB ASC 840 – *Leasing*
- FASB ASC 980 - *Regulated Operations*
- CICA 3065 – *Leases*
- CICA EIC 150 – *Determining whether an arrangement contains a lease*

4. Summary of Canadian GAAP requirements

OPG has classified this lease as an operating lease under Canadian GAAP primarily due to the risk retained by OPG around the used fuel and decommissioning obligations.

OPG records Base Rent and the Initial Lease Payments on a straight line basis. The initial lease payment is recognized on a straight line basis until 2018, the initial term of the lease. This is consistent with the underlying nature of the initial amount and the assumption that the payment was made towards the initial lease term only, which ends in 2018.

The Base Rent is recognized on a straight line basis since April 2008. This basis of accounting is consistent with the OEB's decision which requires OPG to include Base Rent payments on a straight line basis in determining regulated prices.

Prior to the OEB decision, OPG records rent payment as stipulated in the lease agreement since the Bruce Lease payments as specified in the lease agreement were included in the determination of the regulated rates. This accounting is analogous to the accounting for income taxes for the rate regulated operations prior to the amendment made by the AcSB in 2007 to CICA 3465. Prior to rate regulation and after Section 1100 of the CICA handbook became effective, OPG accounts for the base rent payment on as stipulated basis.

Supplemental Rent is contingent on units being operational as such is accounted for as contingent rent and recognized on an accrued basis based on the lease agreement.

Accounting Discussion

The following summarizes the key differences between the two frameworks (US GAAP and Canadian GAAP):

Under US GAAP, the classification, recognition and measurement criteria are substantially converged with Canadian GAAP. As such, there are no material differences expected for OPG's assessment other than the requirement to straight line rent payments from inception.

Differences which are not expected to impact OPG

A. ***Lease classification***

Description of Issue

Although there are areas where the language is slightly different, we would expect the lease classification criteria of operating vs. capital under US GAAP to yield the same result as Canadian GAAP. No difference in lease classification results with respect to the Bruce Lease.

Under ASC 840-10-25-42 "A lessor shall consider all four lease classification criteria in paragraph 840-10-25-1 and both of the following incremental criteria:

a. Collectibility of the minimum lease payments is reasonably predictable. A lessor shall not be precluded from classifying a lease as a sales-type lease, a direct financing lease, or a leveraged lease simply because the receivable is subject to an estimate of uncollectibility based on experience with groups of similar receivables.

b. No important uncertainties surround the amount of unreimbursable costs yet to be incurred by the lessor under the lease. Important uncertainties might include commitments by the lessor to guarantee performance of the leased property in a manner more extensive than the typical product warranty or to effectively protect the lessee from obsolescence of the leased property.

ASC 840-10-25-43 clarifies that "A lease is an operating lease if it does not meet any of the four criteria in paragraph 840-10-25-1 or both of the criteria in the preceding paragraph" (i.e. ASC 840-10-25-42).

Analysis

US GAAP, ASC 840-10-25-1 details the lease classification criteria for lessee and lessor accounting. US GAAP bright line tests are equivalent to those found under

CICA 3063.06 and therefore, we would not expect any difference in Canadian GAAP to US GAAP in this area.

Under Canadian GAAP, CICA 3065.07 states "From the point of view of a lessor, a lease would normally transfer substantially all of the benefits and risks of ownership to the lessee when, at the inception of the lease, all the following conditions are present":

(a) any one of the conditions in paragraph 3065.06; (The bright line tests)

(b) the credit risk associated with the lease is normal when compared to the risk of collection of similar receivables; and

(c) the amounts of any unreimbursable costs that are likely to be incurred by the lessor under the lease can be reasonably estimated. If such costs are not reasonably estimable, the lessor may retain substantial risks in connection with the leased property. This may occur, for example, when the lessor has a commitment to guarantee the performance of, or to effectively protect the lessee from obsolescence of, the leased property."

Under Canadian GAAP, the lease arrangement is classified as an operating lease as OPG has not transfer substantially all the risks with respect to the decommissioning of the stations, especially those risks during the safe storage and the actual decommissioning activities. The costs associated with the decommissioning the stations require a high degree of judgment as there has not been a full decommissioning performed on a CANDU reactor in North American history. The potential variability of the decommissioning liability is significant and is material to the overall lease.

OPG Conclusion

The concept contained ASC 840-10-25-42 (b) is similar to that contained within CICA 3065.07(c). Similarly, US GAAP states that a lease is operating in nature if either condition in ASC 840-10-25-42 is not met. The Bruce lease continues to be classified as an operating lease under US GAAP.

B. Straight-line recognition of lease payments

Description of Issue

OPG commenced recording the Base Rent payment on a straight line basis in April 2008. Under US GAAP, OPG is required to recognize lease revenue on a straight line basis from the inception of the lease in 2001, for operating leases per ASC 840-10-25-1.

Analysis

Since OPG has been recording the deferred revenue receivable (payable) associated with the Bruce Lease commencing in 2008 instead of from the inception of the lease, an adjustment would be applied to reflect the Bruce Lease base rent payments on a straight-line basis calculated since lease inception on a retrospective basis. This is similar to the adjustment identified in the IFRS conversion project as IAS 17 also requires recognition of lease payments on a straight line basis from lease inception.

Conclusion

OPG must straight line base rent payments over the term of the lease from the inception of the lease. The result is an increase on its balance sheet with the corresponding offset to retained earnings.

The journal entries required to record this adjustment for the opening balance sheet on January 1, 2011 would be as follows:

Dr. Deferred Revenues	$59m	
Cr. Retained Earnings		$59m

The entries required during 2011 for the straight lining affect are as follows:

Dr. Income statement	$39m	
Cr. Deferred Revenues		$39m

Presentation and Disclosure

In general, US GAAP requires more disclosure than Canadian GAAP as some of the US GAAP requirements are desirable but not mandatory under Canadian GAAP. Some of the additional disclosures required by OPG as a lessor of the Bruce Power assets are as follows:

a) Minimum future rentals on noncancelable leases as of the date of the latest balance sheet presented, in the aggregate and for each of the five succeeding fiscal years
b) Total contingent rentals included in income for each period for which an income statement is presented[1]

A comprehensive analysis will be performed during preparation of the financial statements when a disclosure checklist is completed. Please refer to US GAAP conversion memo "Financial Statements" for presentation and disclosure considerations relevant to OPG.

[1] Excerpt from E&Y US GAAP Disclosure Checklist Y Form A13 (revised 10 November 2011) Ernst & Young LLP. Pages 154-156.

Appendix A - Other Documentation

The following documentation provides further background on the issues described in this paper:

Document Name	Document
US GAAP - Bruce Lease Opening adjustment - 01 16 2012.xls	Bruce Lease Opening adjustment Feb 9.xls

Transition Adjustment (excluding the initial lease deferral)
- Exclude impact of initial lease deferral and variance account

	Dr (Cr)
US GAAP - Dec 31, 2010 Deferred Lease Receivable balan	(8,487,179)
CGAAP - Dec 31, 2010 Deferred Lease Payable balance	(67,486,583)
Opening Balance Sheet Adjustment	58,999,404
Lease revenue to be recorded during the year ended	39,327,416

US GAAP
Bruce Straight-line lease calculation (with Stub Period Impact)
Nov 2008 to 2036
(millions of dollars)

	Base Rent			Bruce Initial Deferred Revenue			Stub Period Deferred Revenue	Total			
Years	**Base Rent (per agreement)**	**Straight-line Rent**	**Deferred Revenue Dr (Cr) - P&L**	**Amortization (Original)**	**New Amortization**	**Impact**	**Dr (Cr) - P&L**	**Existing**	**Amended lease term**	**Reduction (increase) in revenue**	**B/S - Cumulative Deferred Revenue balance (excluding initial deferred revenue) (Dr)/Cr**
							(69,722,222)				
2001	62,000,000	75,666,667	(13,666,667)	11,724,060	11,724,060	-	-	73,724,060	87,390,727	(13,666,667)	(13,666,667)
2002	63,000,000	75,666,667	(12,666,667)	11,724,060	11,724,060	-	-	74,724,060	87,390,727	(12,666,667)	(26,333,333)
2003	65,000,000	75,666,667	(10,666,667)	11,724,060	11,724,060	-	-	76,724,060	87,390,727	(10,666,667)	(37,000,000)
2004	66,000,000	75,666,667	(9,666,667)	11,724,060	11,724,060	-	-	77,724,060	87,390,727	(9,666,667)	(46,666,667)
2005	67,000,000	75,666,667	(8,666,667)	11,724,060	11,724,060	-	-	78,724,060	87,390,727	(8,666,667)	(55,333,333)
2006	69,000,000	75,666,667	(6,666,667)	11,724,060	11,724,060	-	-	80,724,060	87,390,727	(6,666,667)	(62,000,000)
2007	71,000,000	75,666,667	(4,666,667)	11,724,060	11,724,060	-	-	82,724,060	87,390,727	(4,666,667)	(66,666,667)
2008 (3 months)	18,000,000	18,916,667	(916,667)	2,931,015	2,931,015	-	-	20,931,015	21,847,682	(916,667)	(67,583,333)
2008 (7 months)	42,000,000	44,138,889	(2,138,889)	6,839,035	6,839,035	-		48,839,035	50,977,924	(2,138,889)	(69,722,222)
2008 (2 months)	12,000,000	6,857,988	5,142,012	1,954,010	1,954,010	-	412,558	13,954,010	8,399,441	5,554,569	(64,167,653)
2009	74,000,000	41,147,929	32,852,071	11,813,835	11,813,835	-	2,475,345	85,813,835	50,486,419	35,327,416	(28,840,237)
2010	76,000,000	41,147,929	34,852,071	12,083,160	12,083,160	-	2,475,345	88,083,160	50,755,744	37,327,416	8,487,179
2011	78,000,000	41,147,929	36,852,071	12,083,160	12,083,160	-	2,475,345	90,083,160	50,755,744	39,327,416	47,814,596
2012	80,000,000	41,147,929	38,852,071	12,083,160	12,083,160	-	2,475,345	92,083,160	50,755,744	41,327,416	89,142,012
2013	81,000,000	41,147,929	39,852,071	12,083,160	12,083,160	-	2,475,345	93,083,160	50,755,744	42,327,416	131,469,428
2014	83,000,000	41,147,929	41,852,071	12,083,160	12,083,160	-	2,475,345	95,083,160	50,755,744	44,327,416	175,796,844
2015	85,000,000	41,147,929	43,852,071	12,083,160	12,083,160	-	2,475,345	97,083,160	50,755,744	46,327,416	222,124,260
2016	88,000,000	41,147,929	46,852,071	12,083,160	12,083,160	-	2,475,345	100,083,160	50,755,744	49,327,416	271,451,677
2017	90,000,000	41,147,929	48,852,071	12,083,160	12,083,160	-	2,475,345	102,083,160	50,755,744	51,327,416	322,779,093
2018	92,000,000	41,147,929	50,852,071	12,083,160	12,083,160	-	2,475,345	104,083,160	50,755,744	53,327,416	376,106,509
2019	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	369,433,925
2020	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	362,761,341
2021	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	324,088,757
2022	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	317,416,174
2023	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	278,743,590
2024	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	272,071,006
2025	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	233,398,422
2026	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	226,725,838
2027	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	188,053,254
2028	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	181,380,671
2029	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	142,708,087
2030	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	136,035,503
2031	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	97,362,919
2032	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	90,690,335
2033	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	52,017,751
2034	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	45,345,168
2035	-	41,147,929	(41,147,929)	-	-	-	2,475,345	-	38,672,584	(38,672,584)	6,672,584
2036	32,000,000	41,147,929	(9,147,929)	-	-	-	2,475,345	32,000,000	38,672,584	(6,672,584)	0
Total	1,159,000,000	1,159,000,000	0	122,516,285	122,516,285	-	(0)	1,281,516,285	1,211,794,063	69,722,222	

Balance as at Nov 1, 2008:
122,516,351

Canadian GAAP
Bruce Straight-line lease calculation (with Stub Period Impact)
Nov 2008 to 2036
(millions of dollars)

	Base Rent			Bruce Initial Deferred Revenue			Stub Period Deferred Revenue	Total			
Years	**Base Rent (per agreement)**	**Rent recognized**	**Deferred Revenue Dr (Cr) - P&L**	**Amortization (Original)**	**New Amortization**	**Impact**	**Dr (Cr) - P&L**	**Existing**	**Amended lease term**	**Reduction (increase) in revenue**	**B/S - Cumulative Deferred Revenue balance (excluding initial deferred revenue) (Dr)/Cr**
2001	62,000,000	62,000,000	-	11,724,060	11,724,060	-	-	73,724,060	73,724,060	-	-
2002	63,000,000	63,000,000	-	11,724,060	11,724,060	-	-	74,724,060	74,724,060	-	-
2003	65,000,000	65,000,000	-	11,724,060	11,724,060	-	-	76,724,060	76,724,060	-	-
2004	66,000,000	66,000,000	-	11,724,060	11,724,060	-	-	77,724,060	77,724,060	-	-
2005	67,000,000	67,000,000	-	11,724,060	11,724,060	-	-	78,724,060	78,724,060	-	-
2006	69,000,000	69,000,000	-	11,724,060	11,724,060	-	-	80,724,060	80,724,060	-	-
2007	71,000,000	71,000,000	-	11,724,060	11,724,060	-	-	82,724,060	82,724,060	-	-
2008 (3 months)	18,000,000	18,000,000	-	2,931,015	2,931,015	-	-	20,931,015	20,931,015	-	-
2008 (7 months)	42,000,000	42,000,000	-	6,839,035	6,839,035	-	(5,806,202)	48,839,035	54,645,237	(5,806,202)	(5,806,202)
2008 (2 months)	12,000,000	6,857,988	5,142,012	1,954,010	1,954,010	-	34,356	13,954,010	8,777,642	5,176,368	(629,833)
2009	74,000,000	41,147,929	32,852,071	11,813,835	11,813,835	-	206,137	85,813,835	52,755,627	33,058,208	32,428,375
2010	76,000,000	41,147,929	34,852,071	12,083,160	12,083,160	-	206,137	88,083,160	53,024,952	35,058,208	67,486,583
2011	78,000,000	41,147,929	36,852,071	12,083,160	12,083,160	-	206,137	90,083,160	53,024,952	37,058,208	104,544,792
2012	80,000,000	41,147,929	38,852,071	12,083,160	12,083,160	-	206,137	92,083,160	53,024,952	39,058,208	143,603,000
2013	81,000,000	41,147,929	39,852,071	12,083,160	12,083,160	-	206,137	93,083,160	53,024,952	40,058,208	183,661,208
2014	83,000,000	41,147,929	41,852,071	12,083,160	12,083,160	-	206,137	95,083,160	53,024,952	42,058,208	225,719,417
2015	85,000,000	41,147,929	43,852,071	12,083,160	12,083,160	-	206,137	97,083,160	53,024,952	44,058,208	269,777,625
2016	88,000,000	41,147,929	46,852,071	12,083,160	12,083,160	-	206,137	100,083,160	53,024,952	47,058,208	316,835,833
2017	90,000,000	41,147,929	48,852,071	12,083,160	12,083,160	-	206,137	102,083,160	53,024,952	49,058,208	365,894,042
2018	92,000,000	41,147,929	50,852,071	12,083,160	12,083,160	-	206,137	104,083,160	53,024,952	51,058,208	416,952,250
2019	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	408,010,458
2020	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	399,068,667
2021	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	358,126,875
2022	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	349,185,083
2023	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	308,243,292
2024	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	299,301,500
2025	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	258,359,708
2026	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	249,417,917
2027	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	208,476,125
2028	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	199,534,333
2029	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	158,592,542
2030	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	149,650,750
2031	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	108,708,958
2032	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	99,767,167
2033	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	58,825,375
2034	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	49,883,583
2035	-	41,147,929	(41,147,929)	-	-	-	206,137	-	40,941,792	(40,941,792)	8,941,792
2036	32,000,000	41,147,929	(9,147,929)	-	-	-	206,137	32,000,000	40,941,792	(8,941,792)	0
Total	1,159,000,000	1,159,000,000	0	122,516,285	122,516,285	-	(0)	1,281,516,285	1,275,710,083	5,806,202	

Balance as at Nov 1, 2008:
122,516,351

Base Rent

(in millions)

2001	62	**2010**	76
2002	63	**2011**	78
2003	65	**2012**	80
2004	66	**2013**	81
2005	67	**2014**	83
2006	69	**2015**	85
2007	71	**2016**	88
2008	72	**2017**	90
2009	74	**2018**	92

AMPCO Interrogatory #008

Ref: Exhibit A2, Tab 2, Schedule 1, Business Planning and Budgeting, Page 5

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Preamble: The evidence states "OPG also considers the economic climate, including trends in electricity costs and consumers' ability to pay, in its business planning activities";

a) Please provide a detailed explanation of the how OPG considers trends in electricity costs and consumers' ability to pay in its business planning activities and include any analysis and public consultation activities OPG relies upon to support this statement.

Response

When setting business plan targets, OPG's drive to improve efficiency and maintain a focus on cost control demonstrates its understanding of the economic climate in which it operates. While economic and demographic factors have impacted our labour costs, OPG has been successful in reducing its overall workforce in order to gain efficiencies that assist in the management of electricity consumer's bills.

Please refer to Ex L-1.0-4 CCC-002 for a discussion of consultation activities.

AMPCO Interrogatory #009

Ref: General

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

In OPG's view, do the proposed Payment Amounts represent recovery of an efficient and reasonable level of costs for customers and if so why.

Response

Yes. The proposed payment amounts represent recovery of OPG's reasonable and prudently incurred test period costs resulting from a rigorous and challenging business planning and budgeting process.

AMPCO Interrogatory #010

Ref: Exhibit N1, Tab 1, Schedule 1, Page 19 Darlington Approvals

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Preamble: OPG indicates it is not seeking approvals of the higher levels of OM&A expense or in-service additions. Please confirm the impact of this approach in terms of test period revenue requirement.

Response

There is no impact on the test period revenue requirement from higher expenses or in-service additions for which OPG is not seeking approval.

CCC Interrogatory #006

Ref: Ex. N1/T1/S1/p. 2, Ex. A1/T4/S1/p. 5

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

OPG's evidence is the impact on a typical customer's monthly bill of OPG's application is now $5.94/month, which reflects an increase from the $5.36/month as set out in the September filing. This reflects the 2014-2016 Business Plan that was approved by OPG's Board of Directors on November 14, 2013.

a) Please explain to what extent the Government of Ontario, OPG's shareholder, has explicitly or implicitly approved the initial increase.
b) Please explain to what extent the Government of Ontario, OPG's shareholder, has explicitly or implicitly approved the current increase.
c) Please explain how the Government of Ontario interacts with OPG in terms of making decisions regarding OPG's operations.
d) Please provide all materials provided to the Government of Ontario regarding the current application.
e) Please provide a list of any "shareholder" directives that have impacted the 2014-2015 application.
f) Is the $5.94/month increase inclusive or exclusive of the deferral and variance account impacts?
g) How much of a typical customer's bill relates to OPG-specific amounts? Please provide all assumptions.

Response

a) The Government of Ontario concurred with OPG's 2013 - 2015 Business Plan, which is the basis for the Application filed in September 2013.

b) OPG is currently awaiting a concurrence to its 2014 - 2016 Business Plan, which is the basis for the Impact Statement filed in December 2013.

c) The interactions between the Government of Ontario and OPG are as defined in the Memoradum of Agreement (filed at Ex. A1-4-1, Attachment 2). The Government does not make decisions relating to the day-to-day operation of OPG. It does however have the ability to issue Shareholder directives, it appoints the directors to OPG's Board, it provides financing through the OEFC, and it reviews and concurs with OPG's annual business plans.

d) OPG declines to provide the requested information on the basis of relevance. OPG's Board of Directors ("OPG Board") provides policy direction and oversight to OPG's management. In that capacity, the OPG Board approved this Application and the subsequent Impact Statement based on the 2014 - 2016 Business Plan. The OEB will determine payment amounts based on its assessment of OPG's evidence and any other materials that form part of the record in this proceeding. OPG's communications with its shareholder have no probative value in assessing this material and deciding on appropriate payment amounts for the test period. See related discussion in Ex. L-1.4-17 SEC-020.

e) The following Shareholder directives have impacted the 2014 - 2015 test period:

- A June 16, 2006 directive to begin feasibility studies on refurbishing OPG's existing nuclear units and to begin a federal approvals process for new nuclear units at an existing site.
- An October 14, 2005 directive to enter into the third amendment to the amended and restated lease agreement with Bruce Power L.P.

f) It is inclusive of the deferral and variance account impacts.

h) OPG's regulated generation (including Newly Regulated Hydroelectric) represents approximately 54.6% of Ontario provincial demand. This is based on forecast test period OPG regulated generation of 154.2 TWh, divided by forecast provincial demand during the test period of 282.4 TWh (from Ex. I1-1-2, Table 1, line 10).

Applying this percentage to typical residential consumption of 800 kWh/month (842 kWh/month including line losses, which is the amount OPG must generate to provide 800 kWh at the customer's meter (from Ex. I1-1-2,Table 1, line 1) means that a typical customer purchases approximately 460 kWh/month of OPG production.

Based on a current production-weighted average payment amount for OPG's generation of $49.50/MWh (including Newly Regulated Hydroelectric, where it is assumed that it would have earned $30/MWh, as indicated in Ex. I1-1-2, page 1, line 27), the amount paid by a typical residential consumer for OPG's generation is 460 kWh x $49.50/MWh which equals $22.76/month.

As a percentage of a typical residential bill of $118.69/month, the OPG portion is $22.76/month divided by $118.69/month which equals 19.2%.

Therefore, approximately 19% of a typical customer's bill relates to OPG-specific amounts.

CME Interrogatory #002

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

CME is interested in obtaining the information that OPG, as a government-owned entity, is aware of and can provide in order to help consumers better understand the likely impacts on the total electricity bill charged to each typical or average residential, general service and large volume electricity consumer over the period 2014 to 2016 of OPG's spending plans and the concurrent spending plans of other government-owned entities. In the context of this preamble, please provide the following information:

(a) Please describe the extent to which OPG works with the Minister of Energy and Infrastructure ("MEI") and other government-owned entities, including the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), Hydro One Networks Inc. ("Hydro One") and other large government-owned distributors such as those owned by the cities of Toronto, Ottawa and other large centres in Ontario when developing its ongoing business plans.

(b) Is OPG aware of any estimates developed by the MEI, OPA, IESO, Hydro One and any other municipal government-owned entities that show the year-by-year impacts that their combined activities are likely to have on the total electricity price paid by each of the following types of customer:

(i) a typical or average residential consumer;
(ii) a typical or average general service consumer; and
(iii) a typical or average large volume consumer.

(c) If the answer to the previous question is "yes", then please describe these materials and either produce copies or direct us to an information source where we can obtain copies of these estimates.

Response

(a) As noted in responses to a similar request in EB-2010-0008, regarding the regulated operations, OPG continues to discuss major issues such as the Darlington Refurbishment project and the continued operations of Pickering with the OPA, Hydro One and the Ministry of Energy. As our Shareholder, the Minister of Energy and his staff have discussions with OPG on its business plans on a regular basis. In general, OPG does not discuss its business plans with distributors.

(b) OPG is only aware of the estimates developed by the OPA which are reported in the Long Term Energy Plan.

(c) A detailed PowerPoint presentation is located at http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013 , Module 4: Cost of Electricity Service

CME Interrogatory #003

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Are OPG's Hydroelectric and Nuclear spending plans, over the period 2014 to 2016 likely to prompt a need for incremental transmission or distribution infrastructure? If so, then what are the estimated costs of such infrastructure investments and their likely impact on the "Delivery" line of the bill to consumers?

Response

No.

CME Interrogatory #004

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Has OPG considered the impact of the combined effect of its spending plans and the plans of others that have an impact on the total electricity bill on the need for incremental transmission and distribution infrastructure over the period 2014 to 2016? If so, what are the high-level incremental transmission and infrastructure costs and bill impacts over the period 2014 to 2016?

Response

Please see Ex. L-01.4-3 CME-003.

CME Interrogatory #005

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

In OPG's last payment amounts case (EB-2010-0008) the Board determined that ratepayers should not be required to pay in their rates the amount of compensation OPG pays to its employees in excess of the benchmark determined by the Board in that case to be appropriate. OPG appealed the Board's Decision to the Divisional Court which dismissed the appeal. OPG obtained leave and appealed the Divisional Court's Decision to the Ontario Court of Appeal which allowed OPG's appeal. Around the same time, the Annual Report of the Office of the Auditor General of Ontario was released. That Report was critical of OPG for the compensation it pays to employees.

In the context of the foregoing, please provide the following information:

(a) Have any of the costs OPG has incurred to date in challenging the Board's last payment amounts decision been recorded in deferral accounts? If so, then please provide details of all of the internal and external costs incurred by OPG to date in connection with its Court challenges to the Board's Decision.

(b) What is the current status of the Court process? Did the Board seek leave to appeal the Court of Appeal's Decision to the Supreme Court of Canada? If so, has that request been granted or denied?

(c) Has OPG requested in this case pertaining to a determination of its payment amounts for 2014 and 2015 that ratepayers pay in rates OPG employee compensation at levels which exceed the benchmark found by the Board to be appropriate in OPG's last case? If so, then please quantify the amount of 2014 and 2015 employee compensation being claimed which is in excess of that benchmark.

(d) As a result of the Court of Appeal Decision, is OPG seeking to recover from ratepayers in this proceeding or in any other proceeding any amount of the total compensation it paid to its employees in 2011 and 2012 in excess of the amount determined by the Board in OPG's last case to be appropriate? If the answer is "yes", then please quantify the amount of such compensation for prior years which OPG now seeks to recover

Response

a) No.

b) The OEB's request for leave to appeal is still pending before the Supreme Court of Canada.

c) OPG has requested that its forecast compensation costs for the test period be recovered in the payment amounts to be established in this proceeding. Included in these forecast compensation costs are committed costs payable under the terms of existing collective agreements with its represented employees. OPG expects that the OEB will review its forecast compensation costs and determine payment amounts based on a review of the evidence in this proceeding. For a broader discussion of why OPG's compensation amounts for the test period are reasonable, see Ex. F4-3-1.

d) OPG is not seeking to recover the referenced amounts through this proceeding. The Ontario Court of Appeal decision directed that the issue of the $145M disallowance be remitted back to the OEB to be heard in accordance with the principles set out in the court's decision. To date, no hearing on the matter has been scheduled.

ED Interrogatory #001

Ref: Ex. A1-3-1, Page 4

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

a) Please state the total nuclear payment amount (including riders and all other charges) in $ per MWh in 2013.

b) Please state OPG's requested total nuclear payment amounts (including riders and all other charges) in $ per MWh for: (i) 2014; and (ii) 2015.

Response

a) and b) The requested information is displayed in the chart below. Proposed amounts can be found in OPG's Impact Statement filed December 6, 2013 (Ex. N1-1-1, page 21 and Table 8.)

Nuclear	2013	2014	2015
Base Payment Amount ($/MWh)	51.52	69.91	69.91
Payment Rider Previously Approved ($/MWh)	6.27	4.18	-
Payment Rider Proposed ($/MWh)	-	-	1.59
Total ($/MWh)	57.79	74.09	71.50

PWU Interrogatory #001

Ref: Exh, N1-1-1, Page 2, Lines 12-16 and Page 3, Chart 1

Ref (a) states:

> The main remaining changes from the 2014 - 2016 Business Plan, which net to an approximate $33.0M increase in revenue requirement over 2014 - 2015, are identified below [Chart 1, page 3]. However, OPG is not seeking to recover these amounts in the revised payment amounts and riders. In order to minimize the impact on the proceeding schedule and to keep the Impact Statement to a manageable size, OPG is limiting the update to just the largest changes.

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

a) Please confirm if OPG is seeking to recover these amounts at any other time or in any other way.

b) Please provide the breakdown of the $26M in OM&A cost increase identified in Chart 1.

Response

a) OPG is not planning to seek recovery of these amounts.

b) As noted in Ex. N1-1-1, OPG has updated its Application for the three material impacts arising from the 2014 - 2016 Business Plan. As OPG is not seeking to recover the additional OM&A costs arising from the 2014 - 2016 Business Plan, the information on these impacts beyond that provided in Ex. N1-1-1 is not relevant.

SEC Interrogatory #020

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Please provide a copy of all documents provided to the Board of Directors in approving this application.

Response

OPG declines to provide the requested documents on the basis of relevance and litigation privilege. The same type of material was requested in EB-2010-0008. The OEB Panel in that proceeding decided that the requested material was not relevant, stating:

> The Board has decided not to order production of the materials sought in the CME and CCC motions. In the Board's view, these materials are not relevant to the determination of the issues before the Board in this proceeding. The Board will make its decision on the application and supporting materials filed by the applicant and the evidence of intervenors, all of which is subject to cross-examination.
>
> This evidence goes to the financial and operational impacts of the application and of the alternatives which have been considered.
>
> The material which has been sought through the motions includes the communication between OPG's management and its board of directors, seeking approval to file the application, delegated authority to deal with the proceeding, and the analysis of "likely prospects for success." This material does not form part of the application and does not enhance nor detract from the merits of the application. The evidence is that no changes to the business plans and budgets which underpin the application were sought or made as a result of the board of directors' meeting. These plans and budgets have been filed.
>
> Intervenors can explore, through the witness, whether alternatives to the application should have been considered, and the impacts of OPG's choices. None of this relies on what management presented to the board of directors.
>
> Having found that the materials are not relevant and need not be produced, the question of privilege will not be addressed.
>
> That concludes the Board's decision, and subject to any questions, we can continue with the cross-examination. **EB-2010-0008, Tr. Vol. 1, pages 113-114.**

SEC Interrogatory #021

Ref:

Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Please provide copies of all benchmarking studies, surveys, reports and analysis, undertaken since 2010 by OPG, which have not already been provided in the application or other interrogatory responses.

Response

OPG declines to answer on the basis that this is not an appropriate question. The question ignores the principle of proportionality which underlies the interrogatory process, in that it is overly broad and all encompassing.

The question contemplates the production of every benchmarking study, every survey, every report and every analysis produced by OPG in a period of over three years. OPG's business requires an extensive quantity of documents that may be captured by the question asked in this interrogatory.

If the question was refined to reference specific materials relating to an issue on the approved issues list, OPG could undertake to find relevant materials.

SEC Interrogatory #022

Ref: A1-3-1/p.5

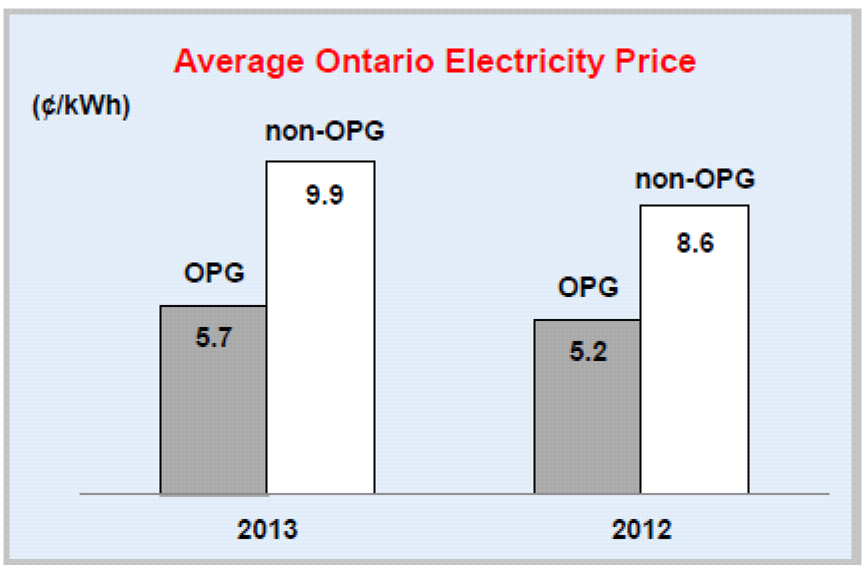
Issue Number: 1.4
Issue: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

Interrogatory

Please update the graph marked "Comparison of OPG and non-OPG Electricity Prices" for the year ended December 31, 2013. Please provide all calculations used to determine the amounts listed, with sources. Please restate the graph, with all supporting calculations, on the assumption that all stranded debt relating to the prescribed facilities (including the newly regulated hydroelectric facilities) were included in the capital of the Applicant, and that portion of the cost continued to be included in rate base.

Response

The graph below is from OPG's audited 2013 financial statements publically filed on March 6, 2014.



Attachment 1 to this response shows the calculations made and the data sources used for those calculations.

OPG has not recalculated this rate under the premise put forward in the interrogatory. OPG continues to calculate rate base in the manner previously approved by the OEB for the purposes of setting just and reasonable rates. The asset values reflected in rate base are prescribed by O. Reg. 53/05.

OPG Average Price Breakdown - Twelve months ended December 31, 2013 & December 31, 2012

		2013 ($millions)	2012 ($millions)	Source	Calculation
	Nuclear Regulated Revenue	2,552	2,719	STAR*	Regulated Rate
	Hydro Regulated Revenue	729	628	STAR*	Regulated Rate
	Reg Hydro Performance Revenue	18	16	STAR*	(MWh in Ont-MWh avg)*avg. HOEP
	Unregulated Hydro Revenue	381	290	STAR* & Hydro One	HOEP
	Unregulated Thermal Revenue	76	104	STAR*	HOEP
A	Subtotal	3,756	3,757		
	Contract Revenue	497	375	OPA & OEFC	Eligible contract costs less market revenue
	Net Other Station Revenue	45	70	STAR*	CMSC, GCG are main components
	Ancillary Revenue	112	69	STAR*	Operating Reserve, Automatic Generation Control, Black Start, Reliability Must Run, Reactive Power.
	Generation Costs	127	109	STAR*	
B	Subtotal	781	623		
C	Gross elec. Gen. sales with Cost Recovery Contracts, Ancl. & Other Rev. (A + B)	4,537	4,380		
D	Production (kWh)	80,280	83,745		
E	Price per kWh (with Cost Rec. Contracts, Ancl. & Other Rev.) in cents (C/D)	5.7	5.2		

**Ontario Settlements Tool for Accural and Reconciliation (STAR)*
***All STAR information is reconciled with the IESO*

Non-OPG Average Price Breakdown - Twelve months ended December 31, 2013 & December 31, 2012

Formula
Non-OPG revenue rate = (Hourly HOEP X Ontario Demand + GA – OPG revenue – Import Cost + Export Revenue)/(Ontario Demand + Exports – OPG production - Imports)

	2013	2012	Source	Calculation	
	($millions)	($millions)			
Hourly HOEP X Ontario Demand	3,718.91	3,391.67	IESO		
GA	7,727.30	6,455.70	IESO		
Import Cost	143.76	133.41	IESO	HOEP X Imports	*(calculation performed by OPG using IESO information)*
Export Revenue	445.55	337.72	IESO	HOEP X Exports	*(calculation performed by OPG using IESO information)*
OPG revenue*	4,410.47	4,272.17	OPG		
	kWh	kWh			
Ontario Demand	140,736.59	141,286.94	IESO		
Imports	4,879.29	4,725.48	IESO		
Exports	18,309.21	14,628.16	IESO		
OPG production	80,280.46	83,744.90	OPG		
Non-OPG revenue rate (cents/kWh)	9.9	8.6			

*Net of Generation Costs