OPG

EB-2013-0321

Board Staff Compendium

Panel 2

Table 1: Previously Regulated Hydroelectric OM&A

	$million	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Acutal	2013 Budget	2013 Actual	2014 Plan	2015 Plan
1	Base	61.8	59.4	68.7	50.1	62.1	60.2	71.9	61.6	74.6	68.6
2	Project	5.3	5.4	9.7	6.6	10	13.6	13	14.7	13.5	17.9
3	SubTotal Operations	67.1	64.8	78.4	56.7	72.1	73.8	84.9	76.3	88.1	86.5
4	Corporate Costs	25.1	22.4	24.8	22.0	26.3	24.5	29.7	26.1	29.8	26.9
5	Centrally Held Costs	20.3	19.6	22.9	15.9	25.5	19.6	25.1	20.7	26.1	26.0
6	Asset Service Fee	2.0	2.1	2.1	1.6	2.0	1.8	1.7	1.6	1.5	1.7
7	SubTotal Other	47.4	44.1	49.8	39.5	53.8	45.9	56.5	48.4	57.4	54.6
8	**Total OM&A**	**114.5**	**108.9**	**128.2**	**96.2**	**125.9**	**119.7**	**141.4**	**124.7**	**145.5**	**141.1**
9	Exhibit N1 Update									**149.2**	**144.2**
10	Exhibit N2 Update									**145.1**	**140.0**

Sources: Exh F1-1-1 Table 1, Exh L-6.1-CCC-17, Exh L-1-Staff-2 Table 15, Exh N2-1-1 Attachment 5

Compound Annual Growth Rate 2010 Actual -2015 Plan
Operations 5.9%
Total 5.2% Exhibit N2

Table 2: Newly Regulated Hydroelectric OM&A

	$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan	2010-2013 Average
11	Base	100.0	106.0	102.9	113.2	103.5	113.4	113.7	103.1
12	Project	39.8	21.6	20.3	16.0	23.1	24.5	32.1	26.2
13	SubTotal Operations	139.8	127.6	123.2	129.2	126.6	137.9	145.8	129.3
14	Corporate Costs	31.4	32.3	36.6	38.8	35.2	42.1	39.6	33.9
15	Centrally Held Costs	19.0	25.1	33.1	47.2	31.8	49.6	48.7	27.3
16	Asset Service Fee	3.6	3.4	3.3	3.1	3.0	2.9	3.0	3.3
17	SubTotal Other	54.0	60.8	73.0	89.1	70.0	94.6	91.3	64.5
18	**Total OM&A**	**193.8**	**188.4**	**196.2**	**218.3**	**196.6**	**232.5**	**237.1**	**193.8**
19	Exhibit N1 Update						**239.3**	**242.6**	
20	Exhibit N2 Update						**234.9**	**237.3**	

Sources: Exh F1-1-1 Table 2, Exh L-6.1-CCC-18, Exh L-1-Staff-2 Table 16, Exh N2-1-1 Attachment 5

Compound Annual Growth Rate 2010 Actual -2015 Plan
Operations 0.8%
Total 4.1% Exhibit N2

unforeseen work or to backfill for vacant regular staff positions until they are filled (See Appendix 2K, Ex. F4-3-1).

3.1.3 OM&A Costs by Resource

In Ex. F1-2-1 Tables 2 and 3, OM&A costs are presented by resource type. Direct plant group labour accounts for approximately 66% of total base OM&A costs in the test period. Labour costs include both regular and non-regular OPG employees, and their related overtime. The remainder of total base OM&A is composed of allocated HTO support group costs (13%), purchased services (10%), materials (6%), and other costs (5%).

3.1.4 Extraordinary Items

Niagara Bridge Divestitures

Included with the Niagara Plant Group's administrative costs is a program to divest certain bridges in the Niagara Region owned by OPG. In 2009, OPG reached an agreement with the City of Thorold to transfer to the city the Laura Secord Bridge, and reached a similar agreement in 2011 for the Niagara Falls Road Bridge. These agreements successfully relieved OPG of all future liabilities associated with these bridges. Negotiations are ongoing with the Niagara Region to divest two more bridges, planned for 2013 - 2014.

Lake Gibson Provision

In addition to bridge divestitures, the Niagara Plant Group's actual administrative costs in 2011 include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS). A long-term liability provision was established by OPG, prior to April, 2005, for the clean-up of contaminated sediments in Lake Gibson. Since that time work has been done by OPG in consultation with the Ministry of Environment (MOE) to assess the risk associated with the contamination and related cleanup. This work culminated in two assessment reports completed and approved by the MOE in December 2009 and February 2012. The reports explain that the contaminated sediments are not considered threats to drinking water drawn from Lake Gibson. Therefore, no remediation of the Lake Gibson sediment contamination is anticipated. Correspondingly, the liability provision was reversed resulting in an extraordinary credit of $19M in 2011.

BUSINESS PLANNING AND BENCHMARKING - REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the regulated hydroelectric business plan and benchmarking and provides a summary of the regulated hydroelectric operating costs.

2.0 OVERVIEW

A summary of the operating costs for 2010 - 2015 is presented in Ex. F1-1-1 Table 1 for the Niagara Plant Group and R.H. Saunders GS, and in Ex. F1-1-1 Table 2 for the newly regulated hydroelectric facilities.

Actual and planned regulated hydroelectric OM&A (Base and Project) expenditures increase by an average of 2.6 per cent /year over the 2010 to 2015 period. A large number of OPG's regulated hydroelectric facilities continue to benchmark well (i.e., top two quartiles) for safety, environmental performance, costs, reliability and availability.

Excluding extraordinary items described in Ex. F1-2-1, section 3 and the Business Transformation re-organization described in Ex. A4-1-1 and A1-4-2, section 4.1, increases in total OM&A are mostly due to labour cost escalation and additional maintenance and project work. The project work includes the start of several major unit overhauls and other structural rehabilitation projects (see Ex.F1-3-1).

The regulated hydroelectric forecasts for the test period are from OPG's 2013 - 2015 Business Plan. The business plan is discussed in section 3.0. Section 4.0 presents the regulated hydroelectric performance targets and section 5.0 presents the regulated hydroelectric benchmarking results.

218.3 million.

Part (b) asked about a rationale for the test period OM&A versus historical. In that response in part (b), which is at the bottom of the page, OPG had provided an explanation for the shift in the OM&A 2012 to 2013, at least the base OM&A, and it spoke about increases to labour rates, unfilled vacancies and other organizational changes.

So if I could ask the OPG staff to go to interrogatory response under Issue 1, Staff 2, table 16, which I believe is page 36 of the PDF. That is Issue 1, Staff No. 2, table 16; I believe it is page 36 of the PDF.

So while they're pulling it up, I just -- and you will see it in a moment. The actual 2013 OM&A for the newly regulated was 196.6 million. And in fact, it is almost identical to the 2012 OM&A.

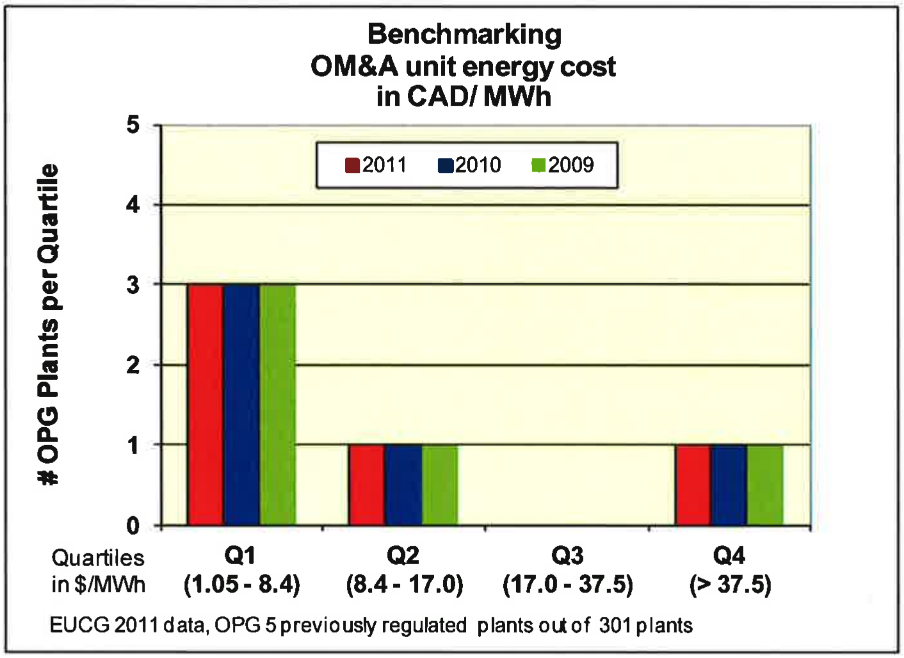
Can you explain that difference with respect to the previous interrogatory, where there were reasons given for the increase but these didn't materialize? Can you explain that?

MR. MAZZA: As we mentioned in the response to 69, a portion of the underage in 2013 was related to unfilled vacancies. There was a plan to fill certain vacancies that didn't materialize, so that is part of it. That is really one of the major items.

And the other one was the business transformation initiative, where there has been a reallocation of some of the staff to the corporate groups; we referred to some of that in the corporate evidence.

average of 99 per cent of the' energy production from these facilities has been ranked has ranked the top two quartiles.

Chart 5a
EUCG Unit Energy Cost Benchmarking Results - Niagara and Saunders



Notes:
99 per cent of Energy Production is in Q1/Q2 (3 year avg.)DeCew Falls I is not included in EUCG Cost Benchmarking Program because EUCG requires concurrent cost and reliability data. DeCew I will be included starting with 2011 data submission.

Chart 5b shows the EUCG quartile ranking for OM&A unit energy costs of the newly regulated facilities. The newly regulated stations have also been generally better than the EUCG average benchmarks. Over the three year period, an average of 87 per cent of the energy production has ranked in the top two quartiles.

Executive Summary

The Ministry of Energy engaged KPMG to assess existing benchmarking studies and to identify organizational and structural opportunities for cost savings at Hydro One and OPG.

The scope of work was to address four main objectives:

- Review and analyze existing benchmarks on compensation, productivity and efficiency
- Identify organizational and structural opportunities for efficiency improvements and Hydro One and OPG
- Prepare a high level 2-3 year plan for improving efficiency without sacrificing reliability and safety
- Develop an analysis that will identify impacts on rate-payers.

7 This report contains the review of existing benchmarking reports on efficiency, productivity and compensation from OPG. From the RFP, this report represents deliverables #1 and #2. In this report we review the following business functions: Nuclear Generation, IT, Finance, HR and Compensation.

Of the eighteen reports provided by OPG, seven reports were used in our benchmark report evaluation covering the five functional areas listed above. Although many reports were provided by OPG, several could not be used in our analysis. Some reports were more than five years old and outside the review timeframe, some reports did not contain benchmarking data and some reports pertained to areas outside the scope of the study.

Of the reports that were used in the study, we found that i) reports did not exist for all business functions and therefore some business functions such as Hydro have not been reviewed in this study ii) In business functions where reports existed, some reports did not review all sub-functions and iii) Some reports provided summary benchmarks at a function level while other reports provided detailed benchmarks at the function, sub-function and activity level.

Given the constraints listed above, the benchmark report evaluation does not cover all business functions and our analysis is also restricted to the level of detail provided by the reports and therefore varies significantly across each business area.

The shortage of data impacted the method in which we planned to identify potential opportunity areas. As a result, an alternate approach was taken to identifying opportunity areas which included significantly more primary data analysis and additional interviews to compare and evaluate operating models for each business function. The outputs from this approach are detailed in a supplementary report, "Assessment of Structural and Organizational Opportunities at OPG".

Benchmarking Reports provided by OPG

8

18 reports were provided by OPG, 7 reports were used in our benchmark report evaluation covering 5 functional areas

OPG Benchmark Reports	Functional Area																			
Report Name	Company wide- Compensation	Generation	IT - Internal	IT - Outsourced	HR - Internal	HR - Outsourced	Finance- Internal	Finance - Outsourced	Administration	Enterprise Risk Management	Regulatory Affairs	Corporate Citizenship	Legal	Source	Operational Focus	Within Evaluation Timeline?	Benchmarking report?	In scope?	Used?	Reason
World-Class Progress Report Finance Final Results							2006, 2008							Hackett	Productivity / Efficiency	Yes	Yes	Yes	Yes	In-scope
OPG Nuclear 2009 Benchmarking Report		2003-2008												ScottMadden	Productivity / Efficiency, Reliability, Safety	Yes	Yes	Yes	Yes	In-scope
2010 Nuclear Benchmarking Report		2004-2009												ScottMadden	Productivity / Efficiency, Reliability, Safety	Yes	Yes	Yes	Yes	In-scope
2011 Nuclear Benchmark Report		2005-2010												ScottMadden	Productivity / Efficiency, Reliability, Safety	Yes	Yes	Yes	Yes	In-scope
OPG HR Metrics Analysis	2006-2008				2006-2008									ScottMadden	Compensation	Yes	Yes	Yes	Yes	In-scope
Benchmarking of Human resources Function Metrics and OPG with Other Electric Utilities	2003-2010				2003-2010									Internal / SocttMadden	Compensation, Productivity / Efficiency	Yes	Yes	Yes	Yes	In-scope
Final OPG IT Cost Benchmark Analysis 2010			2007-2010											EUCG	Productivity / Efficiency	Yes	Yes	Yes	Yes	In-scope
Business Planning and Benchmarking Regulated Hydroelectric		2006-2009												Navigant / CEA / EUCG	Productivity / Efficiency, Reliability	Yes	No	Yes	No	Benchmarks not provided
Achieving World-Class Performance Finance Benchmark Results							2005-2006							Hackett	Productivity / Efficiency	No	Yes	Yes	No	Age of Report
OPG BS&IT IT Benchmarking Results & Analysis 2007			2005-2007											Gartner / EUCG	Productivity / Efficiency	No	Yes	Yes	No	Age of Report
Final OPG IT Cost Benchmark Analysis 2008			2003-2008	2003-2008										Gartner / EUCG	Productivity / Efficiency	Yes	Yes	Yes	No	More recent report used
Final OPG IT Cost Benchmark Analysis 2009			2007-2009											EUCG	Productivity / Efficiency	Yes	Yes	Yes	No	More recent report used
Corporate Executive Board Legal Department Spending and Staffing Benchmarking													2011	Corporate Executive Board	Productivity/Efficiency	Yes	Yes	Yes	No	Scope of Function
Uranium Procurement Program Assessment		2011												Longenecker & Associates	Procurement	Yes	No	No	No	Out of Scope
Uranium Supply Status and Procurement Strategy		2008												Ux Consulting	Procurement	Yes	No	No	No	Out of Scope
Enterprise Risk Management (ERM) Health Check										2010				Corpo Executive Board	ERM	Yes	No	No	No	Out of Scope
OEB Payments Application, OPG Regulatory Affairs Process Review											2012			ScottMadden	Rate Filing	Yes	No	No	No	Out of Scope
OPG Corporate Citizenship Benchmarking Review												2009		Grant Stream	Corporate Social Responsiblity	Yes	Yes	No	No	Out of Scope

UNDERTAKING JT1.10

Undertaking

To provide a definition from EUCG or Navigant of what falls into the OM&A for benchmarking purposes.

Response

The following table presents a comparison of OM&A costs included in EUCG and Navigant hydroelectric benchmarking. All cost categories include labour, materials, purchased services and other costs.

#	Cost Category	EUCG	Navigant	Comments
1	**Facilities Operations** Direct and support costs associated with unit dispatch and water management.	√	√	
2	**Power House Maintenance** Costs associated with the maintenance of equipment and facilities which directly support power generation. Includes equipment from downstream of the intake gate to the unit transformer.	√	√	
3	**Water Ways and Dam Maintenance** Cost of activities associated with maintenance of the waterways, dams and penstocks upstream of the headgate or final valve.	√	√	EUCG collects this cost as non-power house maintenance combined with Buildings and Grounds (below).
4	**Buildings and Grounds Maintenance** Cost of activities associated with maintenance of buildings, facilities and grounds.	√	√	EUCG collects this cost as non-power house maintenance combined with Water Ways and Dams (above).

#	Cost Category	EUCG	Navigant	Comments
5	**Environment and Regulatory** Fish & wildlife, recreation, cultural, other.	√	X	Navigant includes these costs as Regulatory Fees (below).
6	**Regulatory Fees** Gross revenue charge, water usage, taxes, FERC fees etc.	X	X	Navigant 's Regulatory Fees includes Environmental costs (see line 5 above). Navigant's benchmarking cost data is presented with and without Regulatory Fees. OPG uses the data that excludes Regulatory Fees because these costs are outside of management's control and can vary to a large degree.
7	**OM&A Investment Projects** Non-recurring maintenance costs, typically performed on cycles from 2 to 7 years.	√	X	Navigant excludes OM&A projects from "Total Cost" analysis. Both OM&A and capital projects are analyzed separately.
8	**Administration Direct** Administrative costs related to plant activities. Includes all plant administration, HR, and finance costs.	√	√	
9	**Administration Indirect** Administrative costs related to Hydro Business/ Corporate activities (e.g. Hydro central support costs, IT costs, Corporate HR and finance)	√	√	Allocation methods are used to distribute these costs.

Note: Sustaining and new capital additions are not included in benchmarking costs.

Numbers may not add due to rounding.

Table 2

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

Line No.	Costs	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Pension/OPEB Related Costs**[1]	3.9	8.2	13.4	16.0	16.0	15.7
2	**OPG-Wide Insurance**	2.8	2.6	2.0	2.3	2.4	2.4
3	**Performance Incentives**	2.4	1.7	1.4	1.5	1.5	1.5
4	**IESO Non-Energy Charges**	10.1	2.7	3.3	4.4	5.0	5.0
5	**Other**[2]	0.4	0.7	(0.5)	0.9	1.2	1.4
6	**Total**	19.6	15.9	19.6	25.1	26.1	26.0

Notes:
1 See Ex. F4-4-1 Table 1, Note 1.
2 See Ex. F4-4-1 Table 1, Note 2.

Numbers may not add due to rounding

Table 1
(Updated version of Ex. H1-1-1 Table 1)
Deferral and Variance Accounts
Continuity of Account Balances - 2012 to 2013 ($M)

Line No.	Account	Audited Year End Balance 2012[1]	EB-2012-0002 Negotiated Reductions[2]	(a)+(b) EB-2012-0002 Year End Balance 2012[3]	Actual 2013				(c)+(d)+(e)+(f)+(g) Actual Year End Balance 2013	Projected Year End Balance 2013[7]
					Transactions	Amortization[4]	Interest[5]	Transfers		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Previously Regulated Hydroelectric:									
1	Hydroelectric Water Conditions Variance	17.1	0.0	17.1	15.2	(10.3)	0.4	0.0	22.4	42.7
2	Ancillary Services Net Revenue Variance - Hydroelectric	34.0	0.0	34.0	1.8	(20.4)	0.4	0.0	15.8	35.3
3	Hydroelectric Incentive Mechanism Variance	(2.4)	0.0	(2.4)	(2.5)	0.0	(0.0)	0.0	(5.0)	(2.4)
4	Hydroelectric Surplus Baseload Generation Variance	4.1	0.0	4.1	14.9	0.0	0.1	0.0	19.1	8.1
5	Income and Other Taxes Variance - Hydroelectric	(2.5)	0.0	(2.5)	(0.1)	1.5	(0.0)	0.0	(1.1)	(1.1)
6	Tax Loss Variance - Hydroelectric	48.2	0.0	48.2	0.0	(28.9)	0.5	0.0	19.7	19.8
7	Capacity Refurbishment Variance - Hydroelectric	1.1	0.0	1.1	111.1	0.0	0.5	0.0	112.7	114.4
8	Pension and OPEB Cost Variance - Hydroelectric - Historic	2.5	0.0	2.5	0.0	(1.5)	0.0	0.0	1.0	1.0
9	Pension and OPEB Cost Variance - Hydroelectric - Future	12.6	0.0	12.6	0.0	(1.3)	0.0	0.0	11.3	11.3
10	Pension and OPEB Cost Variance - Hydroelectric - 2013 Additions	N/A	N/A	N/A	18.6	0.0	0.0	0.0	18.6	21.5
11	Impact for USGAAP Deferral - Hydroelectric	2.8	0.0	2.8	0.0	(1.7)	0.0	0.0	1.2	1.2
12	Hydroelectric Deferral and Variance Over/Under Recovery Variance	(3.9)	0.0	(3.9)	2.9	2.3	(0.0)	0.0	1.3	4.3
13	Total	113.8	0.0	113.8	162.0	(60.3)	1.8	0.0	217.2	256.0
	Nuclear:									
14	Nuclear Liability Deferral	208.0	(1.8)	206.2	122.7	(74.9)	0.0	0.0	254.0	254.0
15	Nuclear Development Variance	30.2	0.0	30.2	25.6	0.0	0.7	0.0	56.5	69.4
16	Ancillary Services Net Revenue Variance - Nuclear	1.7	0.0	1.7	1.2	(1.0)	0.0	0.0	1.6	1.8
17	Capacity Refurbishment Variance - Nuclear - Capital Portion	1.3	0.0	1.3	4.3	0.0	0.0	0.0	5.7	3.7
18	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	11.8	0.0	11.8	4.0	(7.1)	0.1	0.0	8.9	25.4
19	Bruce Lease Net Revenues Variance - Derivative Sub-Account	230.3	0.0	230.3	24.6	(40.5)	(0.0)	0.0	214.4	189.8
20	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account	80.2	(5.5)	74.8	85.8	(22.4)	0.0	0.0	138.1	139.3
21	Income and Other Taxes Variance - Nuclear	(32.5)	0.0	(32.5)	(4.5)	19.5	(0.3)	0.0	(17.9)	(14.7)
22	Tax Loss Variance - Nuclear	253.3	0.0	253.3	0.0	(152.0)	2.5	0.0	103.8	104.0
23	Pension and OPEB Cost Variance - Nuclear - Historic	51.5	0.0	51.5	0.0	(31.4)	0.5	0.0	20.7	20.5
24	Pension and OPEB Cost Variance - Nuclear - Future	257.6	0.0	257.6	0.0	(25.8)	0.0	0.0	231.8	231.8
25	Pension and OPEB Cost Variance - Nuclear - 2013 Additions	N/A	N/A	N/A	383.7	0.0	0.0	0.0	383.7	375.9
26	Impact for USGAAP Deferral - Nuclear	60.3	0.0	60.3	0.0	(36.2)	0.6	0.0	24.7	24.8
27	Pickering Life Extension Depreciation Variance[6]	N/A	N/A	N/A	(46.8)	56.3	0.0	0.0	9.5	9.5
28	Nuclear Deferral and Variance Over/Under Recovery Variance	6.9	0.0	6.9	39.5	(4.2)	0.3	0.0	42.6	22.1
29	Total	1,160.6	(7.3)	1,153.3	640.2	(318.5)	4.4	0.0	1,478.4	1,457.1
30	Grand Total	1,274.4	(7.3)	1,267.1	802.2	(378.8)	6.2	0.0	1,695.7	1,713.1

Notes
1 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (a) for regulated hydroelectric and Table 2 col. (a) for nuclear.
2 From EB-2012-0002 Payment Amounts Order, App. A, Table 1 col. (b) for regulated hydroelectric and Table 2 col. (b) for nuclear.
3 All balances from EB-2012-0002, Ex. M1-1 Attachment 1, Tables 16A and 17A, col. (c). With the exception of balances at lines 3, 4, 7, 10, 15, 17, 25 and 27, all balances were approved by the OEB in EB-2012-0002 (Payment Amounts Order, App. B, Table B-1, col. (a)).
4 From EB-2012-0002 Payment Amounts Order, App. B, Table B-1, col. (c).
5 Effective January 1, 2013, per EB-2012-0002 Payments Amount Order, no interest is recorded in the Nuclear Liability Deferral Account, and, up to December 31, 2014, no interest is recorded in the Bruce Lease Net Revenues Variance Account and the Future Recovery component of the Pension and OPEB Cost Variance Account on outstanding balances. Up to December 31, 2014, interest is also not being recorded on the 2013 additions to the Pension and OPEB Cost Variance Account. Line 19 includes an interest credit related to the inadvertent overstatement of the amount recoverable in 2013 and 2014 for the Derivative Sub-Account, as noted in Ex. H1-1-1, section 4.13 and OPG's letter to the OEB dated September 26, 2013 referenced therein.
6 Per the EB-2012-0002 Payment Amounts Order, the account reflects a credit of $3.9M per month to ratepayers for the benefit of lower non-asset retirement costs depreciation expense and associated income tax impacts resulting from the revision of the Pickering generation stations' service lives, as discussed in Ex. H1-1-1 section 4.14. No interest is recorded in this account.
7 From Ex. H1-1-1 Table 1, col. (h)

Table 5
Hydroelectric Surplus Baseload Generation Variance Account
Summary of Account Transactions - 2011 to 2013 ($M)

Line No.	Particulars	Actual Mar-Dec 2011	Actual 2012	Projected 2013
		(a)	(b)	(c)
1	**Actual/Projected Foregone Production Due to SBG Conditions[1] (GWh)**	76.5	116.9	178.0
2	**Revenue at $35.78/MWh ($M)**	2.7	4.2	6.4
3	**GRC/Water Rental Costs ($M)**	(1.1)	(1.7)	(2.6)
4	**Addition to Variance Account ($M)** (line 2 + line 3)	1.6	2.5	3.8
5	**Financial Reporting Adjustment [2]**	(1.1)	1.1	0.0
6	**Reported Addition to Variance Account [3] ($M)** (line 4 + line 5)	0.5	3.6	3.8

Notes:

1 From Ex. E1-2-1 Section 3.2.

2 Represents offsetting interperiod financial statement reconciliation adjustments which do not impact the total transactions in the account over the 2011-2012 period.

3 2011 and 2012 additions as presented at line 4 of EB-2012-0002, Ex. H1-1-2 Tables 1b and 1c, respectively

Table 1

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

Line No.	Prescribed Facility	2010 Actual	2011 Actual	2012 Actual	2013 Budget	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	12.2	12.7	13.5
2	**Saunders GS**[1]	6.5	6.9	6.5	6.2	6.3	6.7
3	**Sub total**	18.9	19.5	18.5	18.4	19.1	20.2
	Newly Regulated Hydroelectric:						
4	**Ottawa-St. Lawrence Plant Group**[2]	4.7	5.7	5.1	5.7	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	2.5	2.5	2.5
7	**Northwest Plant Group**	3.4	3.3	3.3	3.8	3.8	3.8
8	**Sub total**	10.0	11.5	10.9	12.4	12.4	12.5
9	**Total**	28.9	31.0	29.4	30.9	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.

peak and the on-peak price, to a 50/50 sharing?

MR. WILBUR: As I said earlier, we anticipate -- with the incentive mechanism as we have proposed, we do not anticipate any changes in our behaviour for the newly regulated or the currently regulated facilities.

MR. ZACHER: And can I just ask you to turn up Exhibit L, tab 5-4, schedule 11?

MR. WILBUR: Is that the interrogatory?

MR. ZACHER: Yes. Yes, it is the IESO Interrogatory No. 4.

MR. WILBUR: No. 4, was that?

MR. ZACHER: That's right. So, Mr. Wilbur, if you look at the answer there to (a), OPG says:

> "The higher the level of incentive to OPG, the greater the degree of potential costs and risks that OPG would be willing to assume to time-shift production."

And what I am just trying to understand is, as I take it, the -- under the current -- under the proposed structure, OPG's downside risk is reduced, because you are guaranteed the regulated rate as compared to whatever the off-peak HOEP price was currently.

And the upside award is also reduced. Instead of getting 100 percent of the difference between -- of the price differential, you only get 50 percent.

And so I take it, all things being equal, you are going to be less incented going forward to time-shift this generation from off-peak to on-peak?

MR. WILBUR: Well, as we said in the response, the higher the level of incentive will allow us to take -- to take slightly more risk and potentially do more time-shifting. But given the incentive that we have proposed, we don't anticipate any change from what we do now.

MR. ZACHER: But what you're saying, if you were to -- if OPG was to receive 100 percent of the price differential as opposed to 50/50, all things being equal, that would lead you -- that would induce you to time-shift more, right?

MR. WILBUR: There is a potential that we could take more risks with our time-shifting, yes.

MR. ZACHER: And so won't the proposed mechanism mean that OPG's newly prescribed assets are going to be less responsive to price and less incented to time-shift?

MR. WILBUR: No. As I've said, we do not -- we do not intend to make any change to the way these facilities operate, on the way they operate currently under the proposal that we have before the Board here.

MR. ZACHER: And that's because there still is some market inducement to shift generation?

MR. WILBUR: There is. Yes.

MR. ZACHER: Okay. And again, have you done any sort of analysis or studying to sort of -- to support that proposition?

MR. SMITH: That question has been asked.

MR. ZACHER: Well, I asked the question with regards to the currently prescribed assets, but this is with

Board Staff Interrogatory #196

Ref: Exh. H1-3-1 pp 1-15

Issue Number: 9.7
Issue: Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

Interrogatory

In the context of the IESO administered electricity spot market,

a) Please indicate the nature of the newly regulated hydroelectric facilities in terms of their name plate capacities and the conditions under which they generally operate in the electricity market (e.g., to serve base load, peak, etc.).
b) Will the newly regulated hydroelectric facilities continue to operate in the same manner in the electricity spot market notwithstanding they will have regulated prices?
c) Is there more or less incentive to produce and supply electricity for dispatching to the spot market given that the prices are regulated and no longer tied to spot market price?

Response

a) The net in-service capacities of the newly regulated hydroelectric facilities are shown in Ex. A1-4-2, Chart 2, pp. 3-4. The conditions under which these facilities generally operate are shown in Table 1 below. The conditions—or plant type—are divided into three categories:
   - Run of River Generating Station
     A "run-of-river" generating station typically has minimal forebay storage and passes some or all of the inflow through one or more turbines on a continuous basis, with the remainder (if any) going over an existing falls or spillway. Many of these facilities operate at both peak and off-peak hours.

   - Intermediate Generating StationAn "intermediate" generating station has "moderate" storage. These facilities have some ability to store water during off-peak hours in their forebays and/or in an upstream reservoir.

   - Peaking Generating StationA "peaking" generating station operates during periods of high energy demand, typically during the daytime on weekdays. These facilities have the ability to store water during off-peak hours in their forebays and/or in an upstream reservoir.

b) Yes, provided the enhanced Hydroelectric Incentive Mechanism ("eHIM") is approved by the OEB as it will incent OPG to continue to follow market price signals (Note: OPG interprets *"...to operate in the same manner..."* as continue to follow market price signals ("HOEP")).

c) Consistent with OPG's prefiled evidence, the inclusion of the newly regulated hydroelectric portfolio in the eHIM (Ex. E1-2-1) will ensure that the incentive to produce electricity will not change with price regulation.

Table 1

River System	Station	Type
Madawaska	Mountain Chute	Peaking
	Barrett Chute	Peaking
	Calabogie	Run-of-river
	Stewartville	Peaking
	Arnprior	Peaking
Ottawa	Otto Holden	Intermediate
	Des Joachims	Intermediate
	Chenaux	Intermediate
	Chats Falls	Run-of-river
Abitibi	Abitibi Canyon	Peaking
	Otter Rapids	Peaking
Montreal	Lower Notch	Peaking
Nipigon	Pine Portage	Run-of-river
	Cameron Falls	Run-of-river
	Alexander	Run-of-river
Aguasabon	Aguasabon	Run-of-river
Kamanistikwia	Silver Falls	Run-of-river
	Kakabeka Falls	Run-of-river
English	Manitou Falls	Run-of-river
	Caribou Falls	Run-of-river
Winnipeg	Whitedog Falls	Run-of-river
Montreal	Indian Chute	Run-of-river
Matabitchuan	Matabitchuan	Run-of-river
Mississippi	High Falls	Run-of-river
Rideau	Merrickville	Run-of-river
Otonabee	Lakefield	Run-of-river

	Auburn	Run-of-river
Trent	Seymour	Run-of-river
	Ranney Falls	Run-of-river
	Hagues Reach	Run-of-river
	Meyersburg	Run-of-river
	Sills Island	Run-of-river
	Frankford	Run-of-river
	Sidney	Run-of-river
Beaver	Eugenia Falls	Intermediate
Muskoka	Trethewey	Run-of-river
	Hanna Chute	Run-of-river
	South Falls	Run-of-river
	Ragged Rapids	Run-of-river
	Big Eddy	Run-of-river
Severn	Big Chute	Run-of-river
South	Elliot Chute	Run-of-river
	Bingham Chute	Run-of-river
	Nipissing	Run-of-river
Sturgeon	Crystal Falls	Run-of-river
Wanapitei	Stinson	Run-of-river
	Conistion	Run-of-river
	McVittie	Run-of-river

would be either intermediate or peaking; is that fair?

MR. WILBUR: I haven't added that up, so I can't confirm your numbers. But I can say that from the list we have shown in table 1 of the interrogatory, Board Staff 196, most of the plants that are listed there are run-of-river.

There is a few peaking plants, but I guess I would characterize it as there is more time-shifting capability in all of the newly regulated plants together than there is at the Beck facility.

MR. ZACHER: Okay. And I am not sure it is necessary to go through it, but in your evidence you identified the newly regulated facilities and identified them in both the megawatt capacity and then, I think in answers to the interrogatories, whether they were peaking, intermediate or run-of-river.

So in any event, the ones that have been characterized as peaking or intermediate, you say have the ability to store water and time shift?

MR. WILBUR: That's correct.

MR. ZACHER: Okay. And those facilities, how do they compare to the time-shifting ability of the Beck facility? Do they have greater or lesser ability to store water and to time-shift generation?

MR. WILBUR: Well, as I said, taken all together, the total of the time-shifting ability of the newly regulated facilities would be considerably greater than that of Beck.

MR. ZACHER: Is that just because the megawatts are greater, or because the operating characteristics of the facilities are different?

MR. WILBUR: Mainly because the megawatts are greater.

MR. ZACHER: Okay. Is there any differences in terms of the operating characteristics, in terms of the ability to store over a period of days, as opposed to a shorter storage horizon?

MR. WILBUR: There is -- some of the peaking facilities in the newly regulated do have longer-term storage, longer than Beck.

But the Beck storage can be used over a few days, as opposed to just one day as well. So it is not limited to just one day.

MR. ZACHER: Can I just ask you to turn up -- there is a report of Mr. Hamal, Exhibit E1, tab 2, schedule 1, attachment 1.

MR. WILBUR: I have that.

MR. ZACHER: If you just turn to page 3 --

MR. SMITH: Sorry, can we just wait until it comes up on the screen?

MR. ZACHER: I think we need to look at attachment 1. Yes, that's it, so page 3.

So, Mr. Wilbur, right at the top of page 3, Mr. Hamal says:

> "The Newly Regulated hydroelectric facilities are typically dispatchable and have significant ability to store water and shift energy across time. Their operating characteristics contrasted

with the previously regulated hydroelectric facilities. Among the units historically covered by HIM, the vast majority of storage capacity was associated with the PGS at Beck which can efficiently time-shift hydro generation on a daily basis, but does not provide longer term storage capacity."

So I just want to understand what the significance of the contrast is. Why is it that the newly regulated facilities have some greater ability to time-shift?

MR. WILBUR: They have -- generally, they have larger storages, so the reservoirs are considerably larger than the PGS reservoir. And at times their inflows are sufficiently small that flow into that reservoir, so that there is a relatively small amount of energy that can be produced from those facilities. And then there is an ability to sometimes wait a week or more before actually generating from that facility.

So that allows a significant time period over which the time-shifting can occur.

MR. ZACHER: So the currently regulated assets, including Beck, have been subject to this hydro incentive mechanism for the past couple of years, including this sort of 50/50 sharing mechanism.

And now OPG is proposing that the newly regulated facilities also be subject to this mechanism, albeit with some changes.

Do you expect the responsiveness, price responsiveness and time-shifting ability of the newly regulated facilities to be the same, or to be more responsive than the previously regulated facilities?

MR. WILBUR: We don't anticipate any change in the responsiveness of these facilities under the mechanism that we have proposed here.

MR. ZACHER: They're not going to be more responsive or less responsive, but just the same?

MR. WILBUR: That is correct.

MR. ZACHER: Have you done any modelling or analysis? I am just trying to understand what the reason for that view is.

MR. WILBUR: The reason is that this mechanism provides an incentive to follow the market price signals. And that is currently the signal we use, that we follow with those resources right now.

Those resources are only paid from the market right now, and so we follow market price to earn the maximum revenue we can from those facilities.

MR. ZACHER: Okay. But that principle aside, have you done any sort of study or analysis?

MR. WILBUR: No, we have not.

MR. ZACHER: Okay. So my understanding of the change from the current incentive mechanism to the enhanced incentive mechanism is that at a high level, really the only difference is that it will eliminate the unintended consequences of incentive payments during surplus base load generation spill; is that right?

MR. WILBUR: That is correct.

MR. ZACHER: Okay. And so with regards to the currently regulated facilities, does OPG expect any change in their operation, in particular their ability to time-shift, as compared to how they operate under the current hydro mechanism?

MR. WILBUR: No, we do not expect any change.

MR. ZACHER: Okay. And that is because the sharing mechanism, 50/50, remains the same, and your view is that incentive isn't in any way dampened by the elimination of this unintended spill payment or the removal of the revenue offset?

MR. WILBUR: That is correct.

MR. ZACHER: Okay. With respect to the newly regulated facilities, I take it that currently they're fully exposed to the hourly Ontario energy price?

MR. WILBUR: They are.

MR. ZACHER: And so they're currently incented to shift generation from low-priced off-peak hours to on-peak high-priced hours?

MR. WILBUR: Correct.

MR. ZACHER: Okay. And OPG's found that under the current system, that is a robust and strong incentive?

MR. WILBUR: That is a strong incentive.

MR. ZACHER: Okay. And do you expect that incentive to be reduced as the result of the proposed eHIM, which I take it sort of reduces the upside reward to OPG from currently 100 percent of the differential between the off-peak and the on-peak price, to a 50/50 sharing?

MR. WILBUR: As I said earlier, we anticipate -- with the incentive mechanism as we have proposed, we do not anticipate any changes in our behaviour for the newly regulated or the currently regulated facilities.

MR. ZACHER: And can I just ask you to turn up Exhibit L, tab 5-4, schedule 11?

MR. WILBUR: Is that the interrogatory?

MR. ZACHER: Yes. Yes, it is the IESO Interrogatory No. 4.

MR. WILBUR: No. 4, was that?

MR. ZACHER: That's right. So, Mr. Wilbur, if you look at the answer there to (a), OPG says:

> "The higher the level of incentive to OPG, the greater the degree of potential costs and risks that OPG would be willing to assume to time-shift production."

And what I am just trying to understand is, as I take it, the -- under the current -- under the proposed structure, OPG's downside risk is reduced, because you are guaranteed the regulated rate as compared to whatever the off-peak HOEP price was currently.

And the upside award is also reduced. Instead of getting 100 percent of the difference between -- of the price differential, you only get 50 percent.

And so I take it, all things being equal, you are going to be less incented going forward to time-shift this generation from off-peak to on-peak?

Monthly SBG Variance Account Entry	= Spill compensation
	+ Incentive payment adjustment
where	
Spill Compensation	= MW_{SBGavg} × (Regulated rate – GRC) × No of hours in month)
Incentive Payment Adjustment	= 'X factor' × $\sum$ [(MW_{SBGi} - MW_{SBGavg}) x $HOEP_i$

The 'X factor' appearing in the Incentive Payment and Incentive Payment Adjustment formulae is established such that the net incentive retained by OPG is equal to one-half the customer cost reduction shown in Table 2. In this manner the benefits arising from time-shifting of energy are shared equally between the customer and OPG as shown in Table 5 below.

Table 5: Expected Payments and Adjustments

M$	2014	2015
'X' factor	35%	31%
Incentive payment	27	30
Incentive payment adjustment	(9)	(12)
eHIM	18	18

Furthermore, OPG proposes to eliminate the revenue requirement adjustment, that no offset attributed to incentive revenue be applied to the revenue requirement based on an expectation of future incentive revenues. The generation of incentive payments for OPG, and the attendant value delivered to the customer, occur simultaneously. As a result, there is no difference in the timing between the customer cost savings and OPG's incentive payments. As a result, there is no need for a revenue requirement offset.

PWU Interrogatory #009

Ref:
(a): Exh E1-2-1, Page5

In EB-2010-0008 Payment Amounts Order, the OEB established the HIM Variance Account to record 50 per cent of HIM net revenues above $10M for the period March through December, 2011 and $14M for calendar year 2012 as a credit to ratepayers. In EB-2012-23 0002 Payment Amounts Order, the OEB set the threshold for 2013 at $13M. Between March 1, 2011 and December31, 2011 actual HIM net revenue was $12.9M. For 2012 actual HIM net revenue was $15.8M. Projected HIM net revenue for 2013 is $8.7M.

(b): Exh E1-2-1, Attachment1, Page8, Lines 3-14

In the reference, OPG states:

OPG's proposal that its incentive payment be based on a 50/50 sharing of the calculated customer benefit is easily misinterpreted. It does not mean that OPG and customers benefit equally from the time shifting, for two reasons. First, there are substantial costs incurred by OPG in conducting the time-shifting that are not part of the 50/50 sharing calculation—those costs are offset by the incentive payment, leaving OPG with a substantially lower net benefit. Second, the calculation gives zero credit for ratepayer benefits that are likely to accrue from GRC payments to the province. Including consideration of both of those issues allows for a more direct comparison of the benefit-sharing in the proposal. In 2014, customers would achieve $34 million in benefits ($18 million in net cost reductions plus the $16 million in GRC payments) while OPG would benefit by $11 million ($18 million eHIM payment less the incremental costs of$7 million), and as a result customers receive 3 out of every 4 dollars in benefits from the time-shifting of generation.

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

a) What is the reason for the projected decline in Hydroelectric Incentive Mechanism ("HIM") net revenue in 2013? Does OPG have the actual HIM net revenue for 2013?

b) Does the existing HIM formula take into account the cost of time shifting at PGS?

c) Why did the OPG decide not to include in the new calculation referred to as the enhanced Hydroelectric Incentive Mechanism (eHIM) the cost of time shifting incurred by the OPG in determining the 50/50 sharing of net revenue?

Response

a) As shown in Ex. H1-1-1, Table 4, the decline in projected 2013 HIM revenues ($8.7M), relative to 2012 actual ($15.8M), was due to an expected 20% reduction in market price spreads resulting in an expected reduction of greater than 50% in the quantity of energy time-shifted in 2013.

Actual 2013 HIM revenues were $18.1M as shown in Ex. L-9.1-17 SEC-132, Attachment 1, Table 4, line 1.

b) No, the current approved HIM formula as shown in EB-2010-0008, Ex. I1-1-1, page 11, does not take into account PGS time shifting costs.

c) OPG did not consider changing the fundamental characteristics of the currently approved HIM formula, to potentially include other formula elements or components such as PGS time shifting costs, when developing the eHIM proposal. As described in Ex. E1-2-1, section 5.3, HIM and eHIM are the preferred incentive mechanisms to provide the consumer benefit as described in Ex. E1-2-1, section 5.1.

Board Staff Interrogatory #061

Ref: Exh E1-2-1 pages 8&9

Issue Number: 5.3
Issue: Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

Interrogatory

OPG states: "When SBG spill cannot be avoided, because the water cannot be time-shifted or stored, it is irrevocably lost. As a result, the monthly average production falls. The SBG spill, which lowers the monthly average production, is compensated for by an entry in the SBG variance account. However, the resulting production profile, reduced by the SBG spill volume also generates incentive payments under the HIM. This is an unintended consequence of interaction between the HIM and SBG Variance Account."

The problem of "unintended" compensation appears to be "double counting" for foregone generation from SBG conditions arising when the monthly production average is reduced by the volume of SBG.

a) To negate this impact, is it not possible to add in the amount of SBG generation foregone to the actual production to get an "average monthly production compensated for SBG" for operating the HIM?
b) Is there a qualitative or quantitative difference between the adjustment above and OPG's proposal: "…induced incentive revenues arising from SBG-related spill should be removed from the SBG Variance Account."?

Response

a) Yes, it is possible to do so. However, doing so would substantially complicate the existing IESO and OPG settlements processes as the IESO does not know the volume or hourly resolution of OPG's SBG spill. By having the IESO perform these calculations, additional financial reporting and settlements processes would need to be developed by both OPG and the IESO.

b) As described in Ex E1-2-1, page 13, the proposed Incentive Payment Adjustment explicitly determines, and corrects for, the impact of SBG spill on the HIM valuation. The Incentive Payment Adjustment calculated by OPG provides the identical outcome as the methodology suggested in the question part a), while not further complicating the existing settlements processes.

Board Staff Interrogatory #063

Ref: Exh E1-2-1

Issue Number: 5.4
Issue: Is the proposed new incentive mechanism appropriate?

Interrogatory

OPG proposes that the enhanced Hydroelectric Incentive Mechanism ("eHIM") apply to the existing hydroelectric facilities plus the newly regulated hydroelectric facilities.

a) The HIM is associated with the PGS facilities operating in tandem with the SAB GS in that water can be diverted for higher value generation. How does the incentive work for run-of-river units, i.e., Saunders, which is one of the originally prescribed hydroelectric facilities?

b) What is OPG proposing for the newly regulated hydroelectric facilities? Can the newly regulated hydroelectric dams store water in the same way that the PGS can? If so, what is the potential for operating the newly regulated units in this manner?

c) Does OPG intend that all of the newly regulated hydroelectric facilities be considered as potential participants in the eHIM, or just the 21 units listed in Exh E1-1-1 Appendix 1?

Response

a) The incentive payment calculation is applied to run-of-river plants using the formula shown on page 12 of Ex. E1-2-1. As would be expected, incentive payments for run-of-river plants tend to be smaller in comparison to peaking plants due to the lower ability to time-shift production due to the generally limited storage capabilities. Differences in production from hour to hour tend to be very small relative to the output of the entire plant. The Saunders station, which is considered a run-of-river plant, has some small and limited ability to time-shift water that is scheduled one day in advance.

b) OPG is proposing to extend the eHIM to all newly regulated hydroelectric stations with modelled production (See Ex. E1-2-1, pages 11 and 12 and Ex. E1-1-1, Appendix 1). None of the newly regulated plants are pumped storage generation facilities but most of the newly regulated plants have the ability for some water storage and can time-shift water from low to high value periods. While the amount of energy that can be time-shifted changes with changing hydrological conditions, the ability of the newly regulated assets to time-shift water can be considerable.

c) OPG intends just the units listed in Ex. E1-1-1 Appendix 1 participate in eHIM.

Witness Panel: Hydro / Energy Markets