SEC Interrogatory #001

Ref: Ex. A1-T3-S2, Drivers of the Deficiency

Issue Number: 1.3
Issue: Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

Interrogatory

a) P. 3. Please confirm that the total deficiency in Charts 1 and 2 is $260.8 million, and that it implies an overall increase in rates of 3.9%.

b) P. 3. Please confirm that, after adjusting for the removal of mitigation and the return to normal levels of taxation, there is a sufficiency of $119.8 million in the test period, and that it implies an overall decrease rates of 1.8%.

c) P. 3. Please disaggregate the components of the driver "changes in cost of capital" into the major sub-components.

Response

a) OPG is able to confirm that the total deficiency is $260.8M which implies an overall increase in average rates of 3.9 per cent.

b) OPG is able to confirm that removal of the suggested items would result in a sufficiency of $119.8M which implies an overall decrease in average rates of 1.8 per cent. However, OPG does not believe that the suggested adjustments are appropriate.

c) The components of the driver "Changes in Cost of Capital" for each of Regulated Hydroelectric and Nuclear are shown in the table below.

$ Millions	Hydro	Nuclear
Changes in deemed Financing Costs	(17.3)	51.7
Changes in Return on Equity	36.3	39.7
	19.0	91.4

Changes in deemed financing costs:

- Declines for hydro due to lower interest rates and a slightly lower rate base.
- Increases for nuclear due to higher rate base.
- Rate base increase results from higher ARO due to Darlington refurbishment, and inclusion of CWIP in rate base

.

Changes in return on equity:

- Increases for hydro due to higher rate.
- Increases for nuclear due to higher rate and increased rate base (as noted above).

SEC Interrogatory #005

Ref: A2-T1-S1, Attachment 2, page 3

Issue Number: 2.2
Issue: Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

Interrogatory

Please confirm that the decision to proceed with the refurbishment of the Darlington nuclear generating station was not, and is currently not, contingent on CWIP being included in rate base. Please provide all documents related to the February 2010 decision that relate in whole or in part to the connection between the decision to proceed and the proposal to include CWIP in rate base.

Response

Confirmed. OPG is unaware of any documents that address the stated connection.

SEC Interrogatory #006

Ref: Ex. D2-T1-S1, page 4, Nuclear Portfolio Project Costs
OEB Decision EB-2007-0905, page 34, Table 2.4, page 37, Table 2.5

Issue Number: 4.4
Issue: Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

Interrogatory

a) Please update Chart 1 (D2-T1-S1;pg 4) and Chart 2 (D2-T1-S1;pg. 5) by adding the amounts forecast in EB-2007-0905 (i.e. the Board approved amounts).

b) Please explain any material variances (i.e. variance of +/- 5%) as between Board approved and 2007 and 2008 actuals.

Response

a) As indicated in Ex. L-1-022, the OEB accepted OPG's 2008 and 2009 forecast of nuclear capital expenditures excluding refurbishment capital expenditures (OEB Decision with Reasons, EB-2007-0905, page 35).

As indicated in Ex. L-1-044, the OEB did not approve aggregate Nuclear OM&A costs in EB-2007-0905. The Board-approved OM&A in the Nuclear revenue requirement, as provided in the EB-2007-0905 Payment Amounts Order, Appendix A, Table 2, includes Nuclear base OM&A, Nuclear outage OM&A, Nuclear project OM&A, allocated corporate and centrally-held OM&A, and the asset service fee.

Charts 1 and 2 have been updated below to include 2008 and 2009 budget amounts.

b) OPG provides budget versus actual variance explanations for 2008 and 2009, where the budget values are those filed by OPG in EB-2007-0905, as follows:
- Project OM&A – Ex. F2-T3-S2, page 2.
- Project Capital – Ex. D2-T1-S1, page 17.

Chart 1
Total Nuclear Project Portfolio Costs – Project OM&A and Capital

	($M)	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget	2011 Plan	2012 Plan
1	Project Portfolio – Capital	186.5	172.0	163.5	172.0	159.4	172.0	172.0	172.0
2	Project Portfolio – OM&A	102.1	118.0	121.2	118.0	120.8	111.7	108.3	111.2
3	**Total Project Portfolio**	**288.6**	**290.0**	**284.7**	**290.0**	**280.2**	**283.7**	**280.3**	**283.2**

Chart 2
Total Nuclear Operations Project Costs – Project OM&A and Capital

	($M)	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget	2011 Plan	2012 Plan
1	Project Portfolio – Capital	186.5	172.0	163.5	172.0	159.4	172.0	172.0	172.0
2	P2/P3 Isolation Project	9.3	17.0	5.7	10.0	14.1	8.8	0.0	0.0
3	Minor Fixed Assets	11.5	17.8	14.2	16.8	17.0	20.2	19.7	19.5
4	**Operations Capital**	**207.2**	**206.8**	**183.4**	**196.8**	**190.6**	**201.0**	**191.7**	**191.5**
5	Project Portfolio – OM&A	102.1	118.0	118.5	118.0	120.8	111.7	108.3	111.2
6	P2/P3 Isolation Project	9.5	26.6	26.6	14.0	22.5	20.6	0.0	0.0
7	PB Continued Ops Project1	0.0	0.0	0.0	0.0	0.4	1.8	19.9	17.0
8	FC Life Cycle Mgmt Project2	0.0	0.0	0.0	0.0	0.0	9.7	7.7	4.0
9	**Operations Project OM&A**	**111.6**	**144.6**	**145.1**	**132.0**	**143.7**	**143.8**	**135.9**	**132.2**
10	**Total Operations Projects**	**318.8**	**351.4**	**328.5**	**328.8**	**334.3**	**344.8**	**327.6**	**323.7**

SEC Interrogatory #007

Ref: Ex. D2-T1-S1, page 4-5, Operations Capital Budget

Issue Number: 4.4
Issue: Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

Interrogatory

At D2-Tab1-S1, pg.1 the forecast capital expenditures are listed as $296.9M and $447.3M for 2011 and 2012 respectively. Please reconcile these figures with Chart 1 and Chart at pages 4 and 5 of D2-T1-S1.

Response

The forecasts quoted at Ex. D2-T1-S1, page 1, line 14 include capital expenditures associated with the nuclear project portfolio, as well as the acquisition of Minor Fixed Assets and generation development projects (Darlington Refurbishment and New Nuclear at Darlington).

Chart 1 presents capital expenditures associated with the nuclear portfolio, while Chart 2 presents Minor Fixed Asset acquisitions in addition to the nuclear portfolio. The following table details the reconciliation.

$M	2011 Plan	2012 Plan
Project Portfolio – Capital (D2-T1-S1 Chart 1 line 1 & D2-T1-S1 Chart 2 line 1)	172.0	172.0
Minor Fixed Assets (D2-T1-S1 Chart 2 Line 3)	19.7	19.5
Operations Capital (D2-T1-S1 Chart 2 and Table 1)	**191.7**	**191.5**
Generation Development Capital (D2-T1-S1 Table 1)	**105.2**	**255.8**
Total Nuclear Capital (D2-T2-S1 Table 1)	**296.9**	**447.3**

SEC Interrogatory #009

Ref: Ex. D2-T2-S1

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

a) What incentive mechanisms have been implemented to help ensure the Darlington Refurbishment is completed on time and within the established budget?

b) At Exhibit D2-2-1 Attachment 1; slide 6 it indicates that the full time equivalent (FTE) related to the Darlington Refurbishment is 98 FTEs in 2009 rising to 148 in 2012. Are these FTE incremental to OPG's current staff or re-assignments from other parts of OPG?

c) What is the total cost related to the incremental FTEs for the Darlington Refurbishment project?

Response

a) The Darlington Refurbishment contract strategy is being developed during preliminary planning of the definition phase. In developing this strategy, OPG will assess various contractual incentive mechanisms to help ensure the completion of the refurbishment on time and within the established budget.

b) As indicated at Ex. D2-T2-S1, Attachment 1, slide 6, the full time equivalent ("FTE") related to the Darlington Refurbishment is 98 FTEs in 2009 and is projected to increase to 148 in 2012. OPG will first seek to re-assign OPG's current staff, however, where this is not possible, OPG will hire externally.

c) OPG does not know in advance whether staff will be re-assigned from other parts of OPG, or hired externally and, thus, cannot provide the total costs related to the incremental FTEs for the Darlington Refurbishment project.

SEC Interrogatory #010

Ref: Ex. D2-T2-S1, Attachment 1, Nuclear Refurbishment Business Plan, page 6
Ex. D2-T2-S1, pages 12 and 16, Chart 2 and Table 3, Darlington Costs

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

Please reconcile the Darlington Refurbishment cost tables referenced above.

Response

Exhibit D2-T2-S1, Attachment 1, Nuclear Refurbishment Business Plan, page 6 includes capitalized interest in years 2011 ($6.1M), and 2012 ($15.8M).

Ex. D2-T2-S1, page 12, Chart 2 and Ex. D2-T2-S1, Table 3 exclude capitalized interest consistent with the inclusion of Construction Work In Progress (“CWIP”) in rate base.

SEC Interrogatory #014

Ref: Ex. D2-T2-S2, Darlington Refurbishment

Issue Number: 4.5
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Interrogatory

Please construct a table which shows the capital, capitalized OM&A, and OM&A for the entire Darlington Refurbishment project up until the date the last unit is forecast to go into service.

Response

Please see the response to the interrogatory in Ex. L-12-003.

SEC Interrogatory #017

Ref: Ex. E2-T1-S1, Attachment 4
Ex. E2-T2-S2, page 9

Issue Number: 5.2
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

At E2-T1-S2, pg 1 the evidence states that the Forced Loss Rate (FLR) is the best estimate of the number of unplanned outage days that OPG will experience in the year due to unforeseen events that result in unit shutdowns. At E2-T1-S1; pg. 11 the evidence states that OPG proposes to reduce its nuclear production forecast by 2.0 TWh for its experience with forced outages and forced extensions due to major unforeseen events.

a) Please explain the methodological difference between accounting for "unforeseen events" via the Forced Loss Rate and OPG's proposal to incorporate an incremental 2TWh reduction in the forecast for "major unforeseen events."

b) Is the forecast FLR currently incorporated into the nuclear forecast?

c) If yes, then why did OPG not adjust the FLR rate to incorporate a larger unforeseen loss factor of 2 TWh?

Response

a) Please see response to Interrogatory L-01-040.

b) Yes, the forecast Forced Loss Rate ("FLR") is currently incorporated into the nuclear forecast (Ex. E2-1-2, Table 1c).

c) OPG believes it is appropriate to separately identify the component of the production forecast associated with major unforeseen events and to hold it at the business unit level rather than include it in the station FLR targets. This approach drives the stations towards stronger FLR performance as they are measured against stretch targets that do not include an allowance for major unforeseen events. In addition, major unforeseen events may occur at any station so it is not appropriate to build this allowance into individual station FLR targets.

SEC Interrogatory #018

Ref: Ex. F2-T1-S1, Attachment 1
Ex. E2-T1-S1, Table 1

Issue Number: 5.2
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

In the OPG business plan presentation at F2-1-1 Attachment 1, pg.9 it identifies an incremental "Additional Site performance target" of 2 TWh for 2011 and 2012. Are the approved corporate target 50.9 and 52 TWh in 2011 and 2012 respectively? If so, why are these different than those sought to be approved for rate making purposes?

Response

No, the approved corporate nuclear generation targets are 48.9 TWh in 2011 and 50 TWh in 2012. These targets form the basis for this Application.

The Additional Site performance target of 2 TWh in 2011 and 2012 represents a stretch target for the Nuclear organization.

SEC Interrogatory #019

Ref: Ex. E2-T1-S1

Issue Number: 5.2
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

a) How is the incentive payment plan related to the corporate performance targets listed at Exhibit F2-1-1, Attachment 8. Please describe what the particular benchmark are used and for which group of staff the performance plan and target apply to. Please indicate how the performance plan compensates for below, meeting or exceeding a corporate benchmark target.

b) If no linkage between incentive plans and benchmark targets exist please indicate why this is so and what steps OPG is taking to link benchmarks with incentive pay.

Response

a) Business Plan targets are part of the scorecard system and impact the awards under the incentive plan. The management group's Annual Incentive Plan ("AIP") for 2010 is based on Corporate, Fleet and Individual performance against a set of objectives outlined in the three scorecards. The Corporate scorecard result sets the total budget available for specific awards. The Fleet results impact their proportion of the Corporate total and then individual scores determine the award given to any employee.

   The scorecards prescribe the weighting of various targets across the Corporate, Fleet and Individual documents. For the Nuclear organization specifically, 20 per cent of the 2010 Nuclear Scorecard is related to meeting corporate generation targets, where maximum payout is earned only if the stretch generation target is reached by Nuclear. Nuclear's stretch targets are aligned to individual scorecard, such that individual targets are met if Nuclear stretch generation targets are met. This AIP model ensures that individual remuneration is subject to meeting both Corporate and Nuclear Scorecard targets.

b) A strong linkage exists between incentive plans and benchmark targets as OM&A and Capital Costs, All Injury Rate, Accident Severity Rate and Collective Radiation Exposure targets constitute another 30 per cent of the Nuclear scorecard, in addition to the 20 per cent related to meeting corporate generation targets.

SEC Interrogatory #020

Ref: Ex. F2-T2-S1, page 12

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

a) Has OPG undertaken any studies in respect to the relationship between overtime costs and its FLR or extensions of planned outages. If yes please provide this analysis.

b) The evidence states that "[i]n the support divisions, the majority of overtime is associated with maintaining CNSC-mandated minimum staff complement. Please provide the costs (actual and forecast) for the 2007 through 2012 costs of overtime costs related to the support divisions. If the staff requirements are mandated please explain why it is not more economical to fulfill these obligations with full time staff.

Response

a) OPG have not undertaken analysis in respect to the relationship between overtime costs and its Forced Loss Rate ("FLR") or extensions of planned outages. However, the use of overtime to respond to an unexpected forced outage or to address an extension to a planned outage is a reasonable measure to take in an effort to return the unit to service as soon as possible.

b) Ex. F2-T2-S1, page 12, lines 27-28 incorrectly states that overtime in the support divisions is associated with maintaining Canadian Nuclear Safety Commission ("CNSC") mandated minimum staff complements. Such minimum staff complements are only applicable to the stations.

   In the support divisions, overtime is driven by the need to provide coverage for absent staff, vacancies and to manage peak work periods and periodic, greater than anticipated workload.

SEC Interrogatory #024

Ref: Ex. F2-T4-S1, page 5
Ex. F2-T4-S1, Table 1

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

a) Please provide a table showing for 2007 through 2012 the costs of the Outage Improvement Strategy, the number of planned outages, the expected outage costs and the expected outage costs without implementation of the Outage Improvement Strategy.

b) Please provide the cost-benefit analysis that was undertaken for this initiative.

Response

a) Please see the table below:

Outage OM&A - Nuclear ($M)

	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Outage Improvement Strategy OM&A Costs (includes training costs)	-	-	-	$2.1	$1.8	$1.9
Number of Planned Outages	6	3	7	9	4	4
Outage Costs	$208.8	$191.1	$246.8	$267.8	$210.1	$196.9
Net Savings from Outage Improvement Strategy (includes training costs)	-	-	-	$1.7	$5.9	$7.9
Expected Outage Costs without implementation of the Outage Improvement Strategy	-	-	-	$269.5	$216.0	$204.8

b) Attachment 1 contains the preliminary cost benefit analysis for the 2009 Outage Improvement Strategy Initiatives that was developed for the 2010 - 2014 Business Plan. Further refinements to this cost benefit analysis are anticipated. Consistent with ScottMadden's recommendation at Ex. F5-T1-S2, page 34 and discussed at Ex. L-14-016, OPG will be encouraging the functional/peer teams to refine and improve their initiatives throughout the remainder of the planning cycle and into implementation.

Initiative Action Plan

Initiative Number: OU-01

NOTE: Hover mouse over section titles for additional details

Initiative Title:	Improve Contractor Management Process
Initiative Number:	OU-01 (Sub-component of OU-02)
Description:	Review and implement fleet contractor management procedure (how contractor work is managed, what work is performed, when the work is scheduled, what support is available, standards for scope change/approval, revise strategic planning of contract work). Drive toward consistent use of contractors across the fleet and improve contractor efficiency, simplify resource planning, improve oversight and quality of contractor function.
Cornerstone/ Metric(s) Targeted:	Cornerstones: Value for Money Metrics: OM&A Base & Outage
Initiative Owner:	Doug RADFORD Maintenance Programs / Jim Woodcroft (Outage liaison)

Expected Results: (Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Darlington	Pickering A	Pickering B
Amount of Gap to be closed by Initiative				
OM&A Base & Outage	2010	$.22 M	$.16 M	$.14 M
OM&A Base & Outage	2011	$.28 M	$.56 M	$.49 M
OM&A Base & Outage	2012	$.36 M	$.81 M	$.63 M
OM&A Base & Outage	2013	$.72 M	$.99 M	$.77 M
OM&A Base & Outage	2014	$.36M	$.81M	$.63M

Financial and Qualitative:

List any other benefits of metric by station/by year - include financial or other. Describe benefit

Metric Name	Year	Darlington	Pickering A	Pickering B
	2010			
	2011			
	2012			
	2013			
	2014			

Additional comments for qualitative benefits

Allows contractors to become more efficient at specialized work in-house.

Risks

Describe below any safety, technical or business risks associated with this initiative

Labor relations uncertainty

Initiative Action Plan

Initiative Number: OU-01

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted

NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010			LOE
Darlington	2011			LOE
Darlington	2012			LOE
Darlington	2013			LOE
Darlington	2014			LOE
Pickering A	2010			LOE
Pickering A	2011			LOE
Pickering A	2012			LOE
Pickering A	2013			LOE
Pickering A	2014			LOE
Pickering B	2010			LOE
Pickering B	2011			LOE
Pickering B	2012			LOE
Pickering B	2013			LOE
Pickering B	2014			LOE
Corp. (specify dept.)	2010			LOE
Corp. (specify dept.)	2011			LOE
Corp. (specify dept.)	2012			LOE
Corp. (specify dept.)	2013			LOE
Corp. (specify dept.)	2014			LOE

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard): Hard

Explain rating

Coordination and procedural changes

People Change Difficulty: Rate difficulty in terms of people changes (Easy, Medium, or Hard): Hard

Explain rating

Focusing the organization on outage dollars and contract costs

Effectiveness Measures:

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

OM&A, Contract Performance Measures quarterly report

Initiative Start/End Dates: Start Date: July 31 2009 End Date: 7/1/2011

Initiative Revision Date:

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments

Initiative Action Plan

Initiative Number: OU-01

1	Update N-PROC-MA-0013 to enable contract success. realignment of milestones to allow contract work to be fully assessed and tendered prior to scope freeze	J. Woodcroft	7/31/2009	10/30/2009	
2	Implement Fleet Outage Strategy	D. Radford	7/31/2009	4/1/2011	
2.1	Identify the work vendors will execute consistently for all years of the plan and across all sites	D. Radford	7/31/2009	3/31/2010	Assign who does what: Base Maint, App A, Project Crews, Contractors. Valves, turbine, electrical, scaffolding. Shift schedule alignment; maximize contractor utilization; maximize float; front-end load schedule
2.2	Develop a plan for standard contracting strategy across the fleet by type of work	D. Radford	7/31/2009	3/31/2010	
2.3	Develop streamlined in-processing and training program to reduce time and cost	D. Radford	4/1/2010	3/31/2011	
2.4	Implement standard contracting strategy across the fleet.	J. Woodcroft	4/1/2010	5/1/2010	
2.5	Implement standard in-processing training program across the fleet.	J. Woodcroft	4/1/2011	5/1/2011	
2.6	Evaluate the viability of launching an equivalency program (training reciprocity with Bruce Power)	Al Shiever	1/1/2010	4/1/2011	
3	Implement Fleet Outage Strategy for Contractor Scope Control	Robin Granger	12/10/2009	3/31/2010	
3.1	Update N-PROC-MA-0013 and SRB N-GUIDE-09300-10000 to incorporate Contractor scope Control strategy from item 3 above	J. Woodcroft	3/1/2010	4/10/2010	
4	Perform an Effectiveness review of the new Contractor strategy in 2011	J. Woodcroft	6/1/2011	7/1/2011	

Other Information:

NOTES:
1. **For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step**
2. **Any additional information, data, resources should be attached to this document**
3. **Include all assumptions for calculations, etc.**

ONTARIO POWER GENERATION

Initiative Action Plan

Initiative Number: OU-02

NOTE: Hover mouse over section titles for additional details

Initiative Title: Improve Outage Execution Process

Initiative Number: OU-02

Description: Improve the execution rate - the amount of work done per day.

Cornerstone/ Metric(s) Targeted:
Cornerstones: Reliability and Value for Money
Metrics: OM&A Base & Outage, Planned Outage Performance

Initiative Owner: Jim Woodcroft (Outage Liaison)

Expected Results: (Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Darlington	Pickering A	Pickering B
Amount of Gap to be closed by Initiative				
OM&A Base & Outage	2010			
OM&A Base & Outage	2011			
OM&A Base & Outage	2012			
OM&A Base & Outage	2013			
OM&A Base & Outage	2014			
Metric Name	**Year**	**Darlington**	**Pickering A**	**Pickering B**
Amount of Gap to be closed by Initiative				
Planned Outage Performance	2010	Meet plan	Meet plan	Meet plan
Planned Outage Performance	2011	Meet plan	Meet plan	Meet plan
Planned Outage Performance	2012	Meet plan	Meet plan	Meet plan
Planned Outage Performance	2013	Meet plan	Meet plan	Meet plan
Planned Outage Performance	2014	Meet plan	Meet plan	Meet plan

Financial and Qualitative:

List any other benefits of metric by station/by year - include financial or other. Describe benefit

Metric Name	Year	Darlington	Pickering A	Pickering B
OM&A Performance / Execution Rate Improvement	2010			
	2011			
	2012			
	2013			
	2014			

Additional comments for qualitative benefits

Increased efficiencies will lead to shorter outage duration and save costs. Note that this initiative is linked to the savings of MA-09 (for Single-source Laundry) pending negotiatied union contract.

Risks

Describe below any safety, technical or business risks associated with this initiative

Initiative Action Plan

Initiative Number: OU-02

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted

NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010			
Darlington	2011			
Darlington	2012			
Darlington	2013			
Darlington	2014			
Pickering A	2010			
Pickering A	2011			
Pickering A	2012			
Pickering A	2013			
Pickering A	2014			
Pickering B	2010			
Pickering B	2011			
Pickering B	2012			
Pickering B	2013			
Pickering B	2014			
Corp. (specify dept.)	2010			
Corp. (specify dept.)	2011			
Corp. (specify dept.)	2012			
Corp. (specify dept.)	2013			
Corp. (specify dept.)	2014			

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard): Hard

Explain rating

Coordination required across multiple functions.

People Change Difficulty: Rate difficulty in terms of people changes (Easy, Medium, or Hard): Hard

Explain rating

Possible jurisdictional issues may develop

Effectiveness Measures:

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

Planned outage day improvement, Work Orders Completed per Day, meet or improve upon business plan duration expectation

Initiative Start/End Dates: Start Date: 7/1/2009 End Date: 3/1/2011

Initiative Action Plan

Initiative Number: **OU-02**

Initiative Revision Date:

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments
1	Develop Outage Execution Rate Improvement Plan	D. Radford	10/1/2009	12/1/2009	Operations Execution Improvements
1.1	Expand the Roving crew to double the size	D. Radford	10/1/2009	10/1/2011	
1.2	Utilize Appendix A/B to better optimize costs and execution rates	Bill Owens Chris Johnston Jim Whyte	10/1/2009	on going	
1.3	Implement an Assessment Quality Program	Bill Owens Chris Johnston Jim Whyte	10/1/2009	10/1/2010	
1.4	Closely script the first 96 hours of the shutdown focusing on operator activities and permit applications	Shane Ryder Ken Gilbert Peter King	9/1/2009	12/1/2010	
1.5	Maintenance to verify permits once operations establishes the permit	Bill Owens Chris Johnston Jim Whyte	10/1/2009	10/1/2010	Maintenance Execution Improvements
1.6	Maintenance to take over ownership of ice plugs	Bill Owens Chris Johnston Jim Whyte	3/1/2010	3/1/2011	
1.7	Reduce the number of PC14's used	Shane Ryder Ken Gilbert Peter King	9/1/2009	9/1/2010	
1.8	Maintenance owns equipment once the permit is applied through MA - WA's not required	Bill Owens Chris Johnston Jim Whyte	9/1/2009	9/1/2010	
1.9	Streamline Work Authorization process	Shane Ryder Ken Gilbert Peter King	10/1/2009	10/1/2010	
1.10	Perform effectiveness review of plan	J.Woodcroft	6/1/2010	7/1/2010	
2	Implement P6 Project to improve resource sharing	J.Woodcroft	4/1/2009	12/15/2009	

Other Information:

NOTES:
1. **For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step**
2. **Any additional information, data, resources should be attached to this document**
3. **Include all assumptions for calculations, etc.**

Initiative Action Plan

Initiative Number: OU-04

NOTE: Hover mouse over section titles for additional details

Initiative Title: Standardize Outage Control Center (OCC) Across Fleet

Initiative Number: OU-04 (Sub-component of OU-02)

Description: Review and implement fleet standards for minimum OCC staffing requirements for best in fleet organizational structure. Ensure OCC staff involvement during outage planning phase. Develop future Outage Managers.

Cornerstone/ Metric(s) Targeted: Cornerstones: Value for Money
Metrics: OM&A Base & Outage, Planned Outage Performance

Initiative Owner: Dan Norrad

Expected Results: (Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Darlington	Pickering A	Pickering B
Amount of Gap to be closed by Initiative		Note: Outage savings in days to be removed from site contengencies		
Generation Revenues	2010	500K	$300K	$600K
	2011	$750K	$450K	$900K
	2012	$1M	$600K	$1.2M
	2013	$2.5M	$750K	$1.5M
	2014	$1.5M	$900K	$1.8M
Metric Name	**Year**	**Darlington**	**Pickering A**	**Pickering B**
		@ $1.01M/day	@ $840K/day	@ $677K/day
OM&A Base and Outage (Outage Cost Savings)	2010	505K	420K	677K
	2011	757K	630K	1.02M
	2012	1.01M	840K	1.35M
	2013	2.52M	1.05M	1.69M
	2014	1.51M	1.26M	2.03M
Metric Name	**Year**	**Darlington**	**Pickering A**	**Pickering B**
Amount of Gap to be closed by Initiative				
Planned Outage Performance (Critical Path Loss)	2010	12 Hours	12 Hours	24 Hours
	2011	18 Hours	18 Hours	36 Hours

Initiative Action Plan

Initiative Number: **OU-04**

	2012	24 Hours	24 Hours	48 Hours
	2013	60 Hours	30 Hours	60 Hours
	2014	36 Hours	36 Hours	72 Hours

Additional comments for qualitative benefits

Ensures that knowledgable people are in the OCC to minimize delays. Make a developmental position for resources from Ops and Maintenance.
Ensure fleet standardization and supporting staffing strategy

Risks

Describe below any safety, technical or business risks associated with this initiative

Release of OCC Staff 3 months prior to outage start and balance of execution. This requires staff from other departments to support.

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted

NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010	$150K		1 FTE incremental increase (@ $150K per)
Darlington	2011	$150K		1 FTE incremental increase (@ $150K per)
Darlington	2012	$150K		1 FTE incremental increase (@ $150K per)
Darlington	2013	$300K		2 FTE incremental increase (@ $150K per)
Darlington	2014	$150K		1 FTE incremental increase (@ $150K per)
Pickering A	2010	$150K		1 FTE incremental increase (@ $150K per)
Pickering A	2011	$150K		1 FTE incremental increase (@ $150K per)
Pickering A	2012	$150K		1 FTE incremental increase (@ $150K per)
Pickering A	2013	$150K		1 FTE incremental increase (@ $150K per)
Pickering A	2014	$150K		1 FTE incremental increase (@ $150K per)
Pickering B	2010	$300K		2 FTE incremental increase (@ $150K per)
Pickering B	2011	$300K		2 FTE incremental increase (@ $150K per)
Pickering B	2012	$300K		2 FTE incremental increase (@ $150K per)
Pickering B	2013	$300K		2 FTE incremental increase (@ $150K per)
Pickering B	2014	$300K		2 FTE incremental increase (@ $150K per)
Corp. (specify dept.)	2010			
Corp. (specify dept.)	2011			
Corp. (specify dept.)	2012			
Corp. (specify dept.)	2013			
Corp. (specify dept.)	2014			

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard) | Easy

Explain rating

Initiative Action Plan

Initiative Number: **OU-04**

People Change Difficulty:

Rate difficulty in terms of people changes (Easy, Medium, or Hard): Hard

Explain rating

Availability and releasability of staff for OCC roles prior to outage

Effectiveness Measures:

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

Critical Path Loss for each outage.
Develop Schedule Adherence on Near Critical Path activities.

Initiative Start/End Dates:

Start Date:

End Date:

Initiative Revision Date:

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments
1	Develop OCC Strategy	Dan Norrad	9/8/2009	Nov 30 /2009	
1.1	Define the organizational structure and staffing requirements of the OCC in MA-0013	Dan Norrad	12/1/2009	1/15/2010	
1.2	Formalize OCC Training into a SAT compliant course and qualification	Dan Norrad	12/1/2009	12/15/2010	
1.3	Implement OCC Strategy	Dan Norrad	Feb 1 2010	May 15 2010	
2	Develop OCC Communications Standard	Dan Norrad	9/8/2009	Nov 30 /2009	
2.1	Develop a standard OCC Six shift status communication package	Dan Norrad	9/8/2009	Nov 30 /2009	
2.2	Develop standard criteria for handoffs in the OCC	Dan Norrad	9/8/2009	Nov 30 /2009	
2.3	Review and Improvement plan of status meetings. (webcast, package, etc)	Dan Norrad	9/8/2009	Nov 30 /2009	
2.4	Implement OCC Communications Standard	Dan Norrad	9/8/2009	Nov 30 /2009	

Other Information:

Darlington; Alan Lapp
Pickering A: Ken Belfall
Pickering B: Leslie Williams

NOTES:

1. **For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step**
2. **Any additional information, data, resources should be attached to this document**
3. **Include all assumptions for calculations, etc.**

Initiative Action Plan

Initiative Number: OU-05

NOTE: Hover mouse over section titles for additional details

Initiative Title:	Implement Outage Duration Improvement Program
Initiative Number:	OU-05 (Sub-component of OU-02)
Description:	Review standard durations on critical path and look for opportunities to reduce/improve. Utilize gap analysis outage over outage and identify and implement opportunities for improvement.
Cornerstone/ Metric(s) Targeted:	Cornerstones: Value for Money Metrics: Planned Outage Performance, Unit Capability Factor
Initiative Owner:	Tim Cullen
Expected Results:	(Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Darlington	Pickering A	Pickering B
		Note: Outage savings in days to be removed from site contengencies		
Generation Revenues	2010	0	0	0
	2011	.683 M	350 K	.750 M
	2012	1 M	500 K	1 M
	2013	2 M	500 K	1 M
	2014	1 M	500 K	1 M
Metric Name	**Year**	**Darlington**	**Pickering A**	**Pickering B**
		@ $1.01M/day	@ $840K/day	@ $677K/day
OM&A Base and Outage (Outage Cost Savings)	2010	$0	0	0
	2011	689.8K	688.8K	1.02M
	2012	1.01M	840K	1.35M
	2013	2.02M	840K	1.35M
	2014	1.01M	840K	1.35M
Metric Name	**Year**	**Darlington**	**Pickering A**	**Pickering B**
		Note: Outage savings in days to be removed from site contengencies		
Planned Outage Performance	2010	0	0	0
	2011	0.683	0.82	1.5
	2012	1	1	2
	2013	2	1	2
	2014	1	1	2

Initiative Action Plan

Initiative Number: OU-05

Financial and Qualitative:

List any other benefits of metric by station/by year - include financial or other. Describe benefit

Metric Name	Year	Darlington	Pickering A	Pickering B
	2010			
	2011			
	2012			
	2013			
	2014			

Additional comments for qualitative benefits

Shorter outage duration, focus on best practices across the fleet and in the industry.

Risks

Describe below any safety, technical or business risks associated with this initiative

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted

NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010	$30 K		
Darlington	2011			
Darlington	2012			
Darlington	2013			
Darlington	2014			
Pickering A	2010	$30 K		
Pickering A	2011			
Pickering A	2012			
Pickering A	2013			
Pickering A	2014			
Pickering B	2010	$30 K		
Pickering B	2011			
Pickering B	2012			
Pickering B	2013			
Pickering B	2014			
Corp. (specify dept.)	2010	$180K		1 FTE @ $150K + $30K for COG gap analysis program
Corp. (specify dept.)	2011			
Corp. (specify dept.)	2012			
Corp. (specify dept.)	2013			
Corp. (specify dept.)	2014			

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard) — Medium

Explain rating

Each site has their own templated back bone structure for outages and as such it should be easy to overlay them for comparison. The team will then look at immediate differences to determine if improvements can be made. Subsequent to this each site will use their template to analyze the gaps outage over outage. This will be enhanced by the COG initiative when we can compare our activity durations to all CANDU plants. Implementation of identified improvements may require site modification.

People Change Difficulty: Rate difficulty in terms of people changes (Easy, Medium, or Hard) — Medium

Initiative Action Plan

Initiative Number: **OU-05**

Explain rating

Depending upon the nature of the change.

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

Effectiveness Measures:

Planned outage days, OM&A, Unit Capability Factor

Initiative Start/End Dates:

Start Date: 9/1/2009

End Date: ongoing

Initiative Revision Date:

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments
1	Prepare OPG Fleet Outage Duration Program	Tim Cullen	9/1/2009	12/15/2009	
1.1	Identify common activities in outages for comparison and tracking outage over outage. Include input and review from IM&CS and Life Cycle Managemnet Engineering	Tim Cullen	9/1/2009	12/15/2009	
1.2	Perform gap analysis and identify improvement opportunities	Outage Peer Team, IM&CS, Life Cycle Management	1/1/2010	Ongoing	
1.3	Redesign work to address identified improvements	Process/Work Program Owner	3/1/2010	ongoing	
1.4	Adjust outage plans for identified improvements	Strategic Planning	7/1/2010	ongoing	
1.5	Perform post-implementation review of change	J. Woodcroft	9/1/2010	12/15/2010	
1.6	Incorporate program into MA-0013	J. Woodcroft	9/1/2010	10/15/2010	
2	Obtain funding and resources for COG Outage Duration Optimization Project	J. Woodcroft	Sept. 1, 2009	12/15/2009	
2.1	Identify common activities in outages for comparison and tracking outage over outage	COG Project Team	Sept. 1, 2009	12/15/2009	
2.2	Perform gap analysis and identify improvement opportunities	COG Project Team	12/15/2009	Sept 1 2010	
2.3	Redesign work to address identified improvements	Process/Work Program Owner	Dec. 1 2010	Dec 1 2011	
2.4	Adjust outage plans for identified improvements	Strategic Planning	2/1/2012	10/1/2012	
2.5	Perform post-implementation review of change	J. Woodcroft	Sept. 1, 2012	12/15/2012	

Other Information:

NOTES:
1. **For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step**
2. **Any additional information, data, resources should be attached to this document**
3. **Include all assumptions for calculations, etc.**

Initiative Action Plan

Initiative Number: OU-07

NOTE: Hover mouse over section titles for additional details

Initiative Title: Formalize Continuous Fleet Outage Improvement Program

Initiative Number: OU-07 (Sub-component of OU-02)

Description: Modify this year's lessons learned process and MA13 improvement / realignment session into OPGs outage program by updating N-PROC-MA-0013 to allow the stations to exchange key learnings from previous years and tackle issues across the fleet. Take over running and maintenance of all outage metrics to support continuous improvement.

Cornerstone/ Metric(s) Targeted: Cornerstones: Reliability and Value for Money
Metrics: OM&A Base & Outage

Initiative Owner: Jim Woodcroft

Expected Results: (Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Corp	Pickering A	Pickering B
OM&A	2010	160K	See note below	See note below
	2011	160K	See note below	See note below
	2012	160K	See note below	See note below
	2013	160K	See note below	See note below
	2014	160K	See note below	See note below

Financial and Qualitative:

List any other benefits of metric by station/by year - include financial or other. Describe benefit

Metric Name	Year	Darlington	Pickering A	Pickering B
	2010			
	2011			
	2012			
	2013			
	2014			

Additional comments for qualitative benefits

Built-in continuous improvement program reinforces fleet alignment and capturing of best practices. The performance gains from this program will be felt across the fleet and all subsequent initiatives identified by it.

Risks

Describe below any safety, technical or business risks associated with this initiative

Obtaining the FTE to ensure proper oversight and gains are realized.

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted

NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010			

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Initiative Number: OU-07

Darlington	2011			
Darlington	2012			
Darlington	2013			
Darlington	2014			
Pickering A	2010			
Pickering A	2011			
Pickering A	2012			
Pickering A	2013			
Pickering A	2014			
Pickering B	2010			
Pickering B	2011			
Pickering B	2012			
Pickering B	2013			
Pickering B	2014			
Corp. (specify dept.)	2010	156k		Cost of meeting ($6K)
Corp. (specify dept.)	2011	156k		Cost of meeting ($6K)
Corp. (specify dept.)	2012	156k		Cost of meeting ($6K)
Corp. (specify dept.)	2013	156k		Cost of meeting ($6K)
Corp. (specify dept.)	2014	156k		Cost of meeting ($6K)

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard) — Easy

Explain rating

Incorporate changes into MA-0013 after peer team review

People Change Difficulty: Rate difficulty in terms of people changes (Easy, Medium, or Hard) — Medium

Explain rating

Obtaining 3 site alignment and willingness to learn from each other

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

Effectiveness Measures

Track the number of repeat events that should have been foreseen and mitigated via the Fleet Outage Lessons Learned Process

Initiative Start/End Dates: Start Date: July, 2009 End Date: 6/1/2010

Initiative Revision Date:

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments
1	Review 2009 FOLL meeting and formulate a continuous Fleet Outage Improvement plan	J. Woodcroft	7/9/2009	8/31/2009	
1.1	Improvement plan to utilize the FOLL and the Corrective Action Program to record and track FOLL issues and actions	J. Woodcroft	7/9/2009	10/31/2009	
1.2	Perform an Effectiveness Review on each FOLL action prior to the next FOLL to ensure issue was effectively resolved and improvements are sustainable	J. Woodcroft	1/1/2010	Ongoing	

Initiative Action Plan

Initiative Number: OU-07

1.3	Track all NSRB, WANO and NO assessments at the Outage Peer Team Meeting to ensure lessons are being learned by the fleet.	J. Woodcroft	On going	On going	
2	Update N-PROC-MA0013 with the requirements for a continuous Fleet Outage Improvement plan	J. Woodcroft	7/9/2009	10/31/2009	
3	Book 2010 and subsequent years FOLL in January and place on Corporate calendar	J. Woodcroft	1/1/2010	Ongoing	
3.1	Perform an Effectiveness review of the outage continuous improvement program	J. Woodcroft	5/1/2010	6/1/2010	
4	Hire fleet Outage Improvement Section Manager to drive continuous fleet improvements and run outage metrics	J. Woodcroft	1/1/2010	6/30/2010	

Other Information:

NOTES:

1. **For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step**
2. **Any additional information, data, resources should be attached to this document**
3. **Include all assumptions for calculations, etc.**

Initiative Action Plan

Initiative Number: TR-06

NOTE: Hover mouse over section titles for additional details

Initiative Title: Improve Fleet Supplemental Worker Training Program

Initiative Number: TR-06 (Sub-component of OU-02 Outage Performance Improvement Initiative)

Description:

This program will support training for supplemental workers employed by vendors contracted by OPGN to perform capital projects and overflow maintenance work. Program scope will address governance, training materials, industry equivalency assessments and oversight of the delivery of the training. Training for supplemental staff is an industry focus area and currently an area of interest for the CNSC. A recent CNSC EQ training observation that identified a vendor instructor not demonstrating procedural compliance with a maintenance procedure and a recent maintenance observation identified use of old revisions of training material for vendor delivered hoisting and rigging training are leading indicators that oversight of training is a focus area. Previously the CNSC has made multiple inquiries about qualifications of supplemental workers, demonstrating qualification caused delay's in field work programs primarily during outages. The benefit of implementing this program will be cost avoidance of outage work program delay's or rework delay's due to unqualified staff performing field work.

The goal for Initiative #TR-06 is to save our fleet at least 5 days through improvements in the two areas listed below :

1. In-Processing and badging time for each incoming supplemental worker for each station outage and each station project, for all 3 OPG Nuclear Sites.

2. Individual Work Tasks Training & Qualification time for each incoming supplemental worker for each station outage and each station project, for all 3 OPG Nuclear Sites.

Funding for the program going to be supported by the work program owners that require the training program.
Site Outage Departments and Projects and Modifications Division proportionate to the volume of labour hours executed by each of the programs.

Cornerstone/ Metric(s) Targeted:

Cornerstone: Reliability - Forced Loss Rate (FLR); Unit Capability Factor
Cornerstone: Human Performance -Training Performance Index (Darlington, Pickering A and Pickering B)

Initiative Owner: Murray Hoggart - Manager, Fleet Maintenance Training Department

Expected Results: (Repeat table below for additional metrics)

Quantitative for Metric Impact:

Metric Name	Year	Darlington	Pickering A	Pickering B
Training Index	2010	80	80	80
Training Index	2011	80	80	80
Training Index	2012	85	85	85
Training Index	2013	85	85	85
Training Index	2014	90	90	90
FLR	2010	1.7	8	5
FLR	2011	1.5	7	4.5
FLR	2012	1.5	5	4
FLR	2013	1.5	5	4
FLR	2014	1.25	4	4

Financial and Qualitative:

List any other benefits of metric by station/by year - include financial or other. Describe benefit

Metric Name	Year	Darlington	Pickering A	Pickering B
Reduced Training Time based on task specific training for supplemental workers	2010	$480k	$480k	$480k

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Reduced Training Time based on task specific training for supplemental workers	2011	$480k	$480k	$480k
Reduced Training Time based on task specific training for supplemental workers	2012	$480k	$480k	$480k
Reduced Training Time based on task specific training for supplemental workers	2013	$480k	$480k	$480k
Reduced Training Time based on task specific training for supplemental workers	2014	$480k	$480k	$480k

Additional comments for qualitative benefits

This initiative has the following benefits:

1. Too much time for Supplemental Worker in-processing, badging, Task Specific Quals Reviews/Confirmations, Training As Required, Testing to Assure Task Competency, and Then Updating of TIMS: needs to be reduced by 5-days per Supplemental Worker.

Savings are 5 days per supplemental worker, avg cost per day is $80/hour times 8 hours = $640.
Cost savings per supplemental worker is $3200.
We use Supplemental Workers for Special Projects and Station Outages.
Planned outages use between 150 and 500 supplemental workers. Savings will range from $480k to $1.6M per station.

In addition, the number of Supplemental Workers varies significantly from Special Project to Special Project. Additional savings can be realized.
Example: The average number of supplemental workers used for special projects is 20.
Average savings for special projects will be $64,000. Average of 6 projects annually = $384k

2. Too much time spent performing Rework on jobs that have been performed by Supplemental Workers:
Temporary Workfoce members are not consistently performing the jobs right the first time. Better task specific qualification training and/or verifications before these workers are approved to perform work independently will reduce re-work.

The savings for Initiative #TR-06 will be reflected in:

1. A reduction in the dollar amount/price for all future contracts for supplemental workers to work at Pickering-A, Pickering-B and Darlington for station outages and special projects.

2. Higher quality, more specifically targeted work task training for each supplemental worker coming here to work on any of our 10 operating nuclear reactor units, which will be realized in higher quality supplemental workforce workmanship and less rework.

Risks

Describe below any safety, technical or business risks associated with this initiative

P&M currently have a team in place that supports the training program for Vendors that employ Building Trades Union (BTU) staff. The team currently is supported by 1Manager, 1 Section Manager (on loan from Safety Training), 1 FLM level (Contracted). Maintenance Training has been providing unfunded support on item by item basis and this has negatively impacted progress on several initiatives like the Training Betterment Initiative.

Resources:

List financial and personnel resources required – indicate any associated capital/O&M project ID numbers and if the project is currently budgeted for – include any budget implications by year and by specific type of budget impacted
NOTE: Although no additional resources are currently budgeted, it is important to note cost and work effort required for the initiative for prioritization purposes

Site/ Department	Year	O&M*	Capital*	Comments (include any numbers of FTEs corresponding to $ or other assumptions)
Darlington	2010			
Darlington	2011			
Darlington	2012			
Darlington	2013			
Darlington	2014			
Pickering A	2010			
Pickering A	2011			
Pickering A	2012			
Pickering A	2013			
Pickering A	2014			
Pickering B	2010			
Pickering B	2011			
Pickering B	2012			
Pickering B	2013			
Pickering B	2014			

Initiative Action Plan

Initiative Number: TR-06

Corp. (NP&T)	2010	$1041k		**Funding for the program going to be supported by the work program owners that require the training program. Site Outage Departments and Projects and Modifications Division proportionate to the volume of labour hours executed by each of the programs. Agreement w/ Line pending.**
Corp. (NP&T)	2011	$1086k		Funding for the program going to be supported by the work program owners that require the training program.
Corp. (NP&T)	2012	$1152k		Funding for the program going forward (2011 onward) to supported by the work program owners that require the training
Corp. (NP&T)	2013	$1178k		Funding for the program going forward (2011 onward) to supported by the work program owners that require the training
Corp. (NP&T)	2014	$1226k		Funding for the program going forward (2011 onward) to supported by the work program owners that require the training

* Note: Initiatives seeking Capital or IT investments must obtain approval through the Asset Investment Screening Committee (AISC). All initiatives requiring budget will require approval and must show clear benefit.

Technical Difficulty: Rate technical difficulty to implement (Easy, Medium, or Hard) — Easy

Explain rating

The required experience and qualifications exist within OPGN organizations today that can support the required due diligence for oversight of this program.

People Change Difficulty: Rate difficulty in terms of people changes (Easy, Medium, or Hard) — Medium

Explain rating

Release of staff with the required experience and qualifications are experiencing significant delay times when moving from an existing role to future role from Pickering.

List any other measures or metrics used to track the success of initiatives – any success that can be measured near-term

Effectiveness Measures:

Cornerstone: Reliability - Forced Loss Rate (FLR); Unit Capability Factor
Cornerstone: Human Performance -Training Performance Index (Darlington, Pickering A and Pickering B)

Initiative Start/End Dates: Start Date: 1/1/2010 End Date: New Ongoing Program

Initiative Revision Date: 8/12/2009

Action Plan:

Action	Description	Owner	Start Date	Completion Date	Comments
1	TQD-510 meet SAT Governance	J.Ballard	no planned dates	no planned dates	NPT not funded / resourced
2	Update/Implement TQD-510	J.Ballard	1/1/2009	12/1/2010	NPT not funded / resourced
3	Establish Contractor Delivery - Vendors and Union Halls	J.Ballard	1/1/2009	10/1/2009	NPT not funded / resourced
4	2009 Equivalency Assessments/Completed, Implemented	J.Ballard	2/8/2009	12/1/2009	NPT not funded / resourced
5	Diligence Review	J.Ballard	1/1/2009	1/1/2010	NPT not funded / resourced

Initiative Action Plan

Initiative Number: TR-06

Other Information:

This initiative is an enabler of OU-01.
Assumptions:

o N-TQD-510 – covers all training and qualification of Vendor staff for all building trades unions (skilled trades), the common conventional, radiological training and qualification that support execution of work by skilled trades.

o This does not address any needs for OPGN NEW BUILD.

o Considers the Pickering VBO, refurbishment of Pickering B, refurbishment Darlington, longer outage windows at Pickering and reduced outage windows at Darlington which will require staff to be trained and qualified. This represents an increase over past outage training needs.

o Delivery of training will be a combination of OPG delivered training and Vendor delivered training.

o Oversight of the training delivered by the vendors must meet OPG standards. This will ensure appropriate due diligence is applied during the training and qualification process.

o Outage training delivery and training oversight will be funded by outage budgets.

o Training material development due to capital projects shall be funded from project funding.

o Funding to support outage training delivery, qualification and Vendor oversight can be funded from outage. Savings due to the change of process should make available the necessary funding with value for money savings above the cost of funding this business program (ie. BTU Carpenter Local delivers scaffold training and we do oversight to ensure standards are maintained during training and qualification process).

o Shops and classrooms for training will be a limiting factor with an increase in trainee throughput if all the training is provided by NPT.

o Line Supervisors perform a minimum of one training observation per quarter to ensure training programs for regular staff meet the expectations for the line organizations. Oversight of Vendor delivered training will be provided by NPT to ensure standards expected by OPG are met. Frequency of observations will not always be a minimum of one per quarter and not limited to one per quarter due to the program peaks and valley's caused by capital projects and outage schedules. Given these schedules there is no baseline training program, the program will need to match the demand caused by capital project or outage schedules which varies from year to year for each site.

The investment/ground work cost for achieving the above referenced goals and savings for Initiative # TR-06 will pay for itself, and consists of:

1. A targeted, Nuclear Training Division led work project in the 2010 calendar year to:
   a. Benchmark, re-design, finalize and implement a more streamlined and efficient in-processing and badging process for supplemental workforce personnel.

   b. Benchmark, re-design, finalize and implement a more streamlined and efficient work task training and qualifications process for each incoming supplemental worker, based upon the EPRI Supplemental Workforce Training and Qualifications Stream-Lining and Standardization Initiative

2. Sustains a foundation of Supplemental Workforce Training and Qualifications Instructors, to be accountable to consistently coordinate, implement and maintain accurate and up-to-date the

NOTES:
1. For a larger initiative with numerous sub-initiatives, it is acceptable to list each sub-initiative on the action plan as a major step
2. Any additional information, data, resources should be attached to this document
3. Include all assumptions for calculations, etc.

SEC Interrogatory #025

Ref: Ex. A2-T1-S1, Attachment 2, page 13

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

Please provide a summary of the problem with tritium emissions referred to in the MD&A, including identifying the internal target and explaining the extent to which, and why, the company was unable to meet that target. Please advise what changes are being made to address the issue, and the cost implications of those changes.

Response

The Management Discussion & Analysis ("MD&A") referred to in the question relates to an internal OPG target for airborne tritium emissions only. OPG Nuclear met its 2009 regulatory target for tritium emissions as set by the Canadian Nuclear Safety Commission. It also benchmarked well against its industry peers in terms of these emissions.

As a result of challenges throughout 2009, OPG's airborne tritium emissions were 2.2 per cent worse than the demanding target that OPG Nuclear set for itself (23,501 curies vs. 23,000 curies). As a result of its experience in 2009, OPG has implemented several process improvements, most of which were administrative in nature and did not have cost implications.

Darlington Generating Station was the primary contributor to emissions exceeding internal target, with tritium issues centered on the start-up and maintenance activities on the Tritium Removal Facility, and dryers being out of service. However, Darlington's performance was still above the industry's best quartile and met all regulatory requirements. Pickering B Generating Station was a secondary contributor to exceeding internal emission limits. The main contributors there were fuelling machine leaks, a heavy water spill, and the unavailability of dryers. Improved maintenance in these areas has led to significant improvements.

Performance to date in 2010 has been at or better than target at all three sites.

SEC Interrogatory #026

Ref: Ex. F2-T2-S1, page 5, A, Table 1

Issue Number: 6.4
Issue: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

Interrogatory

Please calculate the OM&A reduction that would be required for the Darlington GS in order to maintain the 2008 non-fuel benchmark of $25.10 MWh.

Response

The 2008 non-fuel benchmark of $25.10/MWh for Darlington Generating Station is based on a three year average while the targets of $28.22, $26.52 and $26.98 for 2010 - 2012 in Ex. F2-T1-S1, Attachment 8 are based on annual performance.

The Interrogatory references Ex. F2-T2-S1, Table 1 which is Base OM&A only whereas the non-fuel benchmark includes Total OM&A including all operating costs such as Project OM&A and Corporate Support that are outside the Base OM&A table.

In order to maintain the non-fuel benchmark of $25.10/MWh, and given the generation plan for the years in question, the following Total OM&A (including Station, Nuclear Support, Projects and Corporate Support) reduction would be required:

	2010	**2011**	**2012**
Non-Fuel Operating Costs Target ($/MWh)	28.22	26.52	26.98
Net Electrical Production Target (TWh)	27.74	28.86	29.00
Required Non-Fuel Operating Costs Reduction ($M)	**86.61**	**40.89**	**54.62**
Non-Fuel Operating Costs Revised ($/MWh)	25.10	25.10	25.10

SEC Interrogatory #028

Ref: Ex. F2-T1-S1, page 14

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

Has OPG or the CANDU Owners Group undertaken any studies which compare the costs CANDU technology as compared to other nuclear generating technologies? If so please provide these studies.

Response

No, OPG has not undertaken any studies to compare the costs of CANDU technology to other nuclear generating technologies and is unaware of any such studies undertaken by the CANDU Owners Group.

SEC Interrogatory #029

Ref: Ex. F2-T1-S1, Attachment 8, Darlington Benchmark Targets

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

The targeted benchmark for Total Generating Costs per Net MWh, is $35.70 and $36.69 for 2011 and 2012 for the Darlington GS. Please provide the rationale for selecting benchmarks approximately 19% above 22% above the achieved benchmark for Darlington in 2008? Please also provide the inflation assumptions that were used to set the 2011 and 2012 benchmarks.

Response

The actual Total Generating Costs/MWh in 2008 for Darlington was $31.56. The annual targets set for 2011 and 2012 are therefore 13 per cent and 16 per cent higher than the 2008 performance, not 19 per cent and 22 per cent. The annual targets for 2011 and 2012 were set above the performance achieved in 2008 to recognize industry inflation. As explained below, the overall industry inflation assumption is for Total Generating Costs to increase by approximately 4 per cent per annum. Darlington's projected increase of 13 per cent over three years and 16 per cent over four years is therefore reasonable when benchmarked against these industry projections.

During the target setting process (Ex. F2-T1-S1, page 13) industry "inflation" assumptions were derived by ScottMadden and applied to the 2014 industry targets based on historical escalation rates derived from the Electric Utility Cost Group ("EUCG") database. Industry Non-fuel costs were escalated approximately 4.5 per cent per annum, fuel costs by 7.2 per cent per annum, and capital costs by 1.33 per cent per annum based on the EUCG historical data. This equates to an annual increase in Total Generating Costs of approximately 4 per cent.

The four components that make up Total Generating Costs (Total Non-fuel Operating Costs; Fuel Costs; Capital Costs and Net Electrical Production) and their respective 2008, 2011 and 2012 amounts for Darlington Generating Station can be found in the table below. As shown in the table, Total Non-fuel Operating Costs, Fuel Costs and Capital Costs are increasing, while Net Electrical Production is flat.

Total Non-fuel Operating Costs consist of station costs (inclusive of Nuclear support costs), corporate cost allocations and pension burden costs. For these items, Darlington Generating Station's costs are targeted to reduce from the 2008 levels by 9 per cent and 7 per cent in

2011 and 2012, respectively, offset by increases in corporate cost allocations and pension burden costs. Fuel costs from inventory are projected to increase as discussed in Ex. F2-T5-S1. The increase in Darlington Generating Station capital costs is based on an increase projected allocation from the fixed capital portfolio and align with the assumption that more capital will be invested in Darlington Generating Station as it ages and less in Pickering Generating Station as it nears its end of life (see Ex. L-11- 015).

Darlington	2008	2011	2012
Total Non-Fuel Operating Costs (k$)	718,895	765,312	782,611
Fuel Costs (k$)	91,080	134,426	145,646
Capital Costs (k$)	101,887	130,757	136,014
Total Generating Costs (k$)	911,862	1,030,495	1,064,272
Net Electrical Production Target (TWh)	28.89	28.86	29.00
Total Non-Fuel Operating Costs per Net MWh ($/MWh)	$ 24.88	$ 26.52	$ 26.98
Fuel Costs per Net MWh ($/MWh)	$ 3.15	$ 4.66	$ 5.02
Capital Costs per MW DER (k$/MW DER)	$ 29.01	$ 37.23	$ 38.73
Total Generating Costs per Net MWh ($/MWh)	$ 31.56	$ 35.70	$ 36.69

SEC Interrogatory #030

Ref: Ex. F2-T1-S1, Attachment 1

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

a) Please provide an explanation as to why the Darlington GS FLR targets for 2011 and 2012 were chosen at 63 per cent above the achieved 2008 rate.

b) What would be the incremental revenue (at the proposed rates) if it were assumed Darlington GS had an FLR rate remain unchanged from that achieved in 2008 (i.e. .93).

Response

a) The Interrogatory refers to Ex. F2-T1-S1, Attachment 1 that shows a 2-year rolling average Force Loss Rate ("FLR") of 0.93 per cent for Darlington Generating Station in 2008. As shown in Ex. E2-T1-S2, Table 1c, Darlington's FLR targets for 2011 and 2012 are 1.50 per cent in each year. These are one year targets and not rolling averages.

The chart below shows actual yearly FLRs from 2005 – 2009 for Darlington Generating Station.

Year	FLR (%)
2005	1.3
2006	3.2
2007	1.1
2008	0.7
2009	1.6
5 Yr Average	**1.6**

Darlington Generating Station was able to achieve very impressive FLR performance in 2008. However, as the chart indicates, that performance has not been consistently achieved over the past five years.

Darlington 2011 and 2012 FLR targets were based on projected improvements in plant health and human performance factors which is expected to result in Darlington's FLR continuing to be better than CANDU median performance. The 2011 and 2012 FLR targets reflect these multi-year improvement plans and expected performance in these areas.

b) Incremental revenue for 2011 and 2012 would be approximately $10.3M per year based on a 0.17 TWh per year increase in generation resulting from an FLR of 0.93 per cent versus the 1.5 per cent FLR target.

SEC Interrogatory #031

Ref: Ex. F2-T1-S1, page 8
Ex. F2-T1-S1, Attachment 8

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

For the following benchmarks: Forced Loss Factor; Unit Capability Factor; Total Generating Costs per Net MWh; Non-Fuel Operating Costs; Capital Costs per MW DER; please create a table which compares the 2008 median and OPG's achieved benchmarks (shown at F2-T1-S1: pg 8) to the corporate benchmarks established on February 18, 2010. Please have the table show the percentage change from the median and achieved benchmarks to the target benchmarks for 2011 and 2012. Please explain the rationale for any of the target benchmarks that are 5% above either 2008 level.

Response

See Attachment 1.

Attachment A

2008 Benchmarking Results vs. 2011 Targets

	2008 Actuals (Rolling Average)		2011 Targets (Annual)			
Metric	Median	Pickering A	Pickering A	Pickering A % Variance from Median Benchmark	Pickering A % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	37.90	7.00	85%	-82%	Targeting an 82% improvement in FLR is considered a significant improvement
Unit Capability Factor	84.31	56.60	82.55	-2%	46%	Targeting a 46% increase in capability factor is considered a significant improvement
Total Generating Costs per Net MWh	32.31	92.27	72.99	126%	-21%	Targeting a 21% decrease in Total Generating Cost is considered a significant improvement with escalation rates approximately 4% per annum
Non-Fuel Operating Costs per Net MWh	21.28	82.62	63.37	198%	-23%	Targeting a 23% decrease in Total Generating Cost is considered a significant improvement with escalation rates approximately 4% per annum
Capital Costs per MW DER	46.22	32.07	34.63	-25%	8%	Target is significantly better than median results
	Median	Pickering B	Pickering B	Pickering B % Variance from Median Benchmark	Pickering B % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	18.19	4.50	19%	-75%	Targeting a 75% improvement in FLR is considered a significant improvement
Unit Capability Factor	84.31	73.17	80.98	-4%	11%	Targeting an 11% increase in capability factor is considered a significant improvement
Total Generating Costs per Net MWh	32.31	58.68	55.64	72%	-5%	Targeting a 5% decrease in Total Generating Costs is considered a significant improvement with escalation rates approximately 4% per annum
Non-Fuel Operating Costs per Net MWh	21.28	50.95	48.95	130%	-4%	Targeting a 4% decrease in Total Generating Costs is considered a significant improvement with escalation rates approximately 4% per annum
Capital Costs per MW DER	46.22	32.44	12.25	-73%	-62%	Target is significantly better than median results
	Median	Darlington	Darlington	Darlington % Variance from Median Benchmark	Darlington % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	0.93	1.50	-60%	61%	Target is significantly better than median results; See Response to IR #30 (a)
Unit Capability Factor	84.31	91.99	93.89	11%	2%	
Total Generating Costs per Net MWh	32.31	30.08	35.70	11%	19%	See Ex. L-12-029
Non-Fuel Operating Costs per Net MWh	21.28	25.10	26.52	25%	6%	See Ex. L-12-029
Capital Costs per MW DER	46.22	18.79	37.23	-19%	98%	See Ex. L-12-029

2008 Benchmarking Results vs. 2012 Targets

	2008 Actuals (Rolling Average)		2012 Targets (Annual)			
Metric	Median	Pickering A	Pickering A	Pickering A % Variance from Median Benchmark	Pickering A % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	37.90	5.00	32%	-87%	Targeting an 87% improvement in FLR is considered a significant improvement
Unit Capability Factor	84.31	56.60	85.27	1%	51%	Targeting a 51% increase in capability factor is considered a significant improvement
Total Generating Costs per Net MWh	32.31	92.27	71.30	121%	-23%	Targeting a 23% decrease in Total Generating Cost is considered a significant improvement withescalation rates approximately 4% per annum
Non-Fuel Operating Costs per Net MWh	21.28	82.62	62.38	193%	-25%	Targeting a 25% decrease in Total Generating Cost is considered a significant improvement with escalation rates approximately 4% per annum
Capital Costs per MW DER	46.22	32.07	27.74	-40%	-13%	Target is significantly better than median results
	Median	Pickering B	Pickering B	Pickering B % Variance from Median Benchmark	Pickering B % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	18.19	4.00	6%	-78%	Targeting a 78% improvement in FLR is considered a significant improvement
Unit Capability Factor	84.31	73.17	84.72	0%	16%	Targeting an 16% increase in capability factor is considered a significant improvement
Total Generating Costs per Net MWh	32.31	58.68	54.67	69%	-7%	Targeting a 7% decrease in Total Generating Costs is considered a significant improvement with escalation rates approximately 4% per annum
Non-Fuel Operating Costs per Net MWh	21.28	50.95	47.54	123%	-7%	Targeting a 7% decrease in Total Generating Costs is considered a significant improvement with escalation rates approximately 4% per annum
Capital Costs per MW DER	46.22	32.44	13.03	-72%	-60%	Target is significantly better than median results
	Median	Darlington	Darlington	Darlington % Variance from Median Benchmark	Darlington % Variance from Actual 2008 Results to Target	
Forced Loss Factor	3.79	0.93	1.50	-60%	61%	Target is significantly better than median results; See Response to IR #30 (a)
Unit Capability Factor	84.31	91.99	94.09	12%	2%	
Total Generating Costs per Net MWh	32.31	30.08	36.69	14%	22%	See Ex. L-12-029
Non-Fuel Operating Costs per Net MWh	21.28	25.10	26.98	27%	8%	See Ex. L-12-029
Capital Costs per MW DER	46.22	18.79	38.73	-16%	106%	See Ex. L-12-029

SEC Interrogatory #032

Ref: Ex. F2-T1-S1, Attachment 8

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

OPG has established benchmark targets for the nuclear stations on both total generating costs; and non-fuel operating costs. For Darlington GS a benchmark for 2011 has been established for Total Generating Costs which is 18.7% higher than the actual benchmark achieved by that generating station in 2008 (i.e. $35.50 MWh vs. $30.08 MWh). For Non-Fuel Operating Costs the benchmark is only 5.7% higher than the benchmark achieved in 2008 benchmark (i.e. $26.52 MWh vs. $25.10 MWh).

a) Why is there a difference in percentage increase targeted for the fuel vs. non-fuel benchmark?

b) The percentage difference change between Total Generating Costs and the Non-Fuel Generating Cost target benchmarks and the 2008 achieved benchmarks vary for Darlington, Pickering A, Pickering B (13%, 2.4% and -1.3% for 2011 and 14.5%, 1.8% and -.01% for 2012 respectively). Please explain this apparent inconsistency in fuel vs. non-fuel benchmark targets...

Response

Please see response to Interrogatory L-12-029.

SEC Interrogatory #035

Ref: Ex. F3-T1-S2, Table 2, and OEB Decision EB-2007-0905, page 57

Issue Number: 6.9
Issue: Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

Interrogatory

Please explain the apparent discrepancies as between the Nuclear Support corporate costs shown in the Board decision at page 57 (Board Approved) and the budget figures for 2007, 2008 and 2009 (e.g., $236.6M vs. $250.56M / $263.7 vs. $269.1 / $262.4 vs. $267).

Response

In 2007, the budgeted nuclear support corporate costs were $246.2M. The $236.6M identified in the interrogatory is the actual costs for 2007.

The difference in the amount of Corporate Support and Administrative Costs allocated to Nuclear for 2007 is an increase of $4.3M. This increase reflects budget accountability transfers from the Nuclear business to the Corporate Support groups. The transfers include moving the cost for the finance department in Nuclear Inspection Maintenance Services to the Finance group and moving the cost of the Nuclear Leadership Training Department to the Human Resources group.

For explanations of the 2008 and 2009 differences, please refer to Ex. L-01-096.

SEC Interrogatory #036

Ref: Ex. F4-T3-S1, page 31

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Please revise Chart 1 on page 31 to show OPG variance from the 50^{th} percentile.

Response

Below is the comparison of the same occupations in the Chart 11 on page 31 to the 50^{th} percentile of the market. As noted in the evidence, OPG believes that the 75^{th} percentile is a more accurate market considering the high technical skills required by nuclear staff, who are under-represented in the market data. Even at the 50^{th} percentile one-third of the occupations are at market.

Salary % Variance from the 50th Percentile	
Operation Technician - Senior	2%
Operating Technician - Entry	-3%
Senior Business Developer	2%
Project Financial Analyst - Senior	2%
Project Financial Analyst - Fully Qualified	1%
Engineer - Specialist or Group Leader	15%
Engineer - Fully Qualified	21%
Engineer - Developmental	22%
Engineer - Entry	20%
Technologist - Advanced Specialist or Supervisor	15%
Technologist - Fully Qualified	17%
Technologist - Developmental	16%
Technologist - Entry	25%
Senior Daily Trader/Power Trader	29%
Environment - Advanced Specialist or Supervisor	22%
Environment - Fully Qualified	35%
Industrial Nurse	-3%
Safety - Advanced Specialist or Supervisor	11%
Safety - Specialist or Group Leader	20%
Puchasing Supervisor	17%
Junior Buyer	23%
Fleet Manager	10%
Regulatory Analyst - Advanced Specialist or Supervisor	10%
Regulatory Analyst - Specialist or Group Leader	17%
Regulatory Analyst - Fully Qualified	5%
Warehouse Supervisor	30%
Maintenance Supervisor	21%
Maintenance Techician - Dual Trade	7%
Maintenance Planner	38%
Labourer	21%

SEC Interrogatory #037

Ref: Ex. F4-T3-S1

Issue Number: 6.8
Issue: Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

a) Please provide a list of the corporate attributes that were used by Mercer Consulting to choose the OPG Comparator group.

b) Were the prospective comparator groups discussed with OPG management. If so did OPG request any changes to the originally proposed comparator group. If so please provide the original comparator group proposed by Mercer.

c) Please explain the reasons for using a Comparator group composed of 50 per cent public companies.

d) Please explain why no U.S. nuclear operators were included in the study.

e) Please explain the 50% weighting for health sector employers and the absence of other larger public employers like Universities and Provincial and Federal Governments or agencies.

Response

a) The corporate attributes used were as per the recommendation from the Agency Review Panel as found in their 2007 report. The Agency Review Panel further suggested that the comparators be 50 per cent from the public sector and 50 per cent from the private and that the target market level should be the 50th percentile. The recommendation is as follows:

> Have careful regard for appropriate comparator organizations in the public and private sectors of similar size, scope and complexity. (p. 19)

b) The comparators used in the 2009 benchmarking study were provided to Mercer by OPG.

c) Following the Agency Review Panel's recommendation, 50 per cent public companies was used to structure the comparator group.

d) Only organizations in Ontario were used as comparators in keeping with the Agency Review Panel's recommendations.

e) There are few public sector organizations in Ontario that are large, unionized, require highly technical skills and operate on a 24/7/365 basis. Some organizations in the health care sector do meet these conditions.

SEC Interrogatory #040

Ref: Ex. C2-T1-S1, page 1

Issue Number: 8.1
Issue: Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

Interrogatory

a) The evidence states that "OPG is continuing to investigate the impacts of the OEB approved revenue requirement treatment on its ability to fully recover its nuclear liabilities". Please outline these concerns.

b) Has OPG commissioned a study or developed terms of reference for such a study. If yes please provide the terms of reference.

Response

See the response to the interrogatory in Ex. L-01-129. OPG has not commissioned a study nor has OPG developed a terms of reference for such a study.

SEC Interrogatory #041

Ref: Ex. A2-T1-S1, Attachment 2, page 7

Issue Number: 10.1
Issue: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Interrogatory

Please advise the amounts of regulatory assets included in the financial records due to the Tax Loss Variance Account for each of 2008, 2009 and 2010, and reconcile the amount claimed in the Application to those amounts and to the $292 million recognized in 2009 per the financial statements.

Response

The following table compares Tax Loss Variance Account entries in Ex. H1-T1-S1 with financial statement entries shown in Ex. A2-T1-S1 for 2008 and 2009. Figures are not provided for 2010, as the 2010 amount in the Application is a projection for the entire year and OPG has not yet issued its annual financial statements for 2010.

$M	**Entries for 2008**	**Entries for 2009**	**Cumulative total as at Dec. 31, 2009**
Exhibit H1-T1-S1[1]	126.1	168.2	294.3
OPG's Financial Statements[2]	-	295.0	295.0
Difference	126.1	(126.8)	(0.7)

Notes:
1. Ex. H1-T1-S1, Table 1b for 2008 /1c for 2009, lines 4 + 17, columns (b)+(c)+(d)
2. Ex. A2-T1-S1, Attachment 2, page 113

Exhibit H1-T1-S1 presents the Tax Loss Variance Account in the periods to which the entries to the account pertain, rather than the periods in which the amounts were recognized for financial accounting purposes. The financial statements show the entire amount as entered in 2009 because the account was established following the OEB's decision in EB-2009-0038, which was issued on May 11, 2009. Prior to that time OPG had no basis for recording the regulatory asset for this account for financial accounting purposes.

The difference in the cumulative total balance of ($0.7M) is due to rounding.

The $292M cited in the question excludes interest improvement at the OEB-prescribed rate for variance and deferral accounts. The amount of $295M recognized in the 2009 financial statements includes interest improvement.

Witness Panel: Deferral and Variance Accounts, Payment Amounts and Regulatory Treatments

SEC Interrogatory #042

Ref: Ex. D2-T2-S1, page 12
Ex. H1-T1, Capacity Refurbishment Account

Issue Number: 10.4
Issue: Is the proposed continuation of deferral and variance accounts appropriate?

Interrogatory

In respect to the Capacity Refurbishment Account, which books variances between planned and actual expenditures on refurbishment activity at Darlington and Pickering stations, is it OPG position that regulation 53/05 requires the continuation of a variance and deferral account for nuclear refurbishment? If yes please indicate which sections the regulation OPG relies upon for this interpretation?

Response

Yes, it is OPG's position that section 6(2).4 of O. Reg. 53/05 requires continuation of a variance account for nuclear refurbishment and other activities. This view is consistent with the OEB's Decision in EB-2007-0905 (page 123) and the OEB's Payment Amounts Order dated December 2, 2008, paragraph 11 and Appendix F.

SEC Interrogatory #043

Ref: Report of the Board (EB-2006-0064)

Issue Number: 12.2
Issue: What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

Interrogatory

a) Please provide any studies that OPG has undertaken in respect to incentive regulation referenced above.

b) Please provide any reports provided to OPG executives in respect to possible incentive regulation.

c) In OPG's view are there any legislative (including regulations) impediments to an incentive regulation scheme for setting payments.

Response

a) and b)
OPG is in a very preliminary stage of its analysis and there are no results available for review. Were there results to review at this time, OPG would decline to provide the requested material. Such studies and reports would be protected by litigation privilege. In addition, the requested information goes beyond the scope of the issues list approved by the OEB.

c) No.

SEC Interrogatory #044

Ref: Ex. D1-T1-S2, Attachment 1 (Niagara Tunnel Project)

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 1. Please provide a copy of the report and recommendations of the Dispute Review Board.

b) P. 1. Please provide a copy of the agreement with OEFC increasing the facility limit to $1.6 billion.

c) P. 1. Please show full calculations of the LUEC of under 7 cents and the equivalent Power Purchase Agreement price of under 10 cents, in both cases including all necessary assumptions and the sources for those assumptions.

d) P. 3. Please provide a copy of the non-binding Principles of Agreement in 2008 and the non-binding Term Sheet in February 2009.

e) P. 3. Please advise the members of the Major Projects Committee in November 2008.

f) P. 3. Please provide the agreement or other document setting out the new arrangement between the Applicant and Strabag, including the Project Execution Plan.

g) P. 12. Please provide a copy of the Chestnut Park Accord Addendum.

h) P. 12. Please confirm that the methodology for forecasting the cost of the project is the same as that used for the original budget estimates.

i) P. 12. Please provide a copy of the analysis on which the XXXX month contingency is based.

j) App. B. Please re-run the cost model using the higher ROE now being sought by the company, and report the impact on the results.

Response

a) OPG declines to provide the requested document as a review of this document would necessarily involve inquiry into issues that are not relevant to an update of the project's current status, but relate instead to matters that are covered by the OEB's express determination not to review the prudence of projects that will not close to rate base in the test period.

b) Attached is the Amending Agreement to the Credit Facility Agreement between OPG and the OEFC for the purpose of financing the Niagara Tunnel Project (Attachment 1).

c) The requested calculations are shown in Attachment 2.

d) See response to part a).

e) David McMillan (Chair), Ian Ross, Marie Rounding, Bill Sheffield, David Unruh.

f) See response to part a).

g) OPG declines to produce this document because it is not relevant to a status update for the Niagara Tunnel project. The Chestnut Park Accord Addendum ("CPAA") outlines the protocol that OPG has agreed to follow for trades work assignment on OPG work. In the case of the Niagara Tunnel which is new construction, all of the construction work was assigned as Building Trades work.

h) Yes, the same cost model (Work Breakdown Structure and Cost Breakdown Structure) is being used.

i) See response to part a).

j) The Niagara Tunnel Project costs model was re-run based on a return of equity of 9.85 per cent. The following are the resulting changes. The Levelized Unit Energy Cost ("LUEC") and Power Purchase Agreement ("PPA") rates are not affected as the discount rate of 7 per cent is unchanged (see response to Interrogatory L-6-002 for details).

Costs - Present Value

Filed: 2010-08-12
EB-2010-0008
L-12-044
Attachemnt 2

Capital Costs	($M)	886.5
Operating Costs		
GRC	($M)	117.8
OM&A	($M)	1.1
Capital Tax	($M)	3.8
Large Corporation Tax	($M)	0.6
NPV - Total (2005$)	($M)	1009.8

Assumptions:
1) PV date July 1, 2005
2) Operating cash flows assumed to occur in June of each year
3) Discount Rate 7%
4) Total Project cost of $1.6B (includes $286.6M of Interest During Construction)
5) 100% assigned to Capital Cost Allowance (CCA) Class 1 which includes "Dams, tunnel, buildings & other structures"
6) Capital costs include working capital requirements which has been calculated assuming:
   a) on average revenues paid to OPG based on a 37 day lag
   b) on average OPG pays OM&A based on a 14 day lag
   c) on average GRC is paid immediately, 0 day lag
7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
10) OM&A costs of $.11M (2005$M/year) escalated by CPI
11) Capital Tax Rate: 2005 .3%, 2006 .3%, 2007 .3%, 2008 .3%, 2009 .23%, 2010 .15%, 2011 .08%, disappears after 2011
12) Large Corporation Tax Rate: 2005 .18%, 2006 .13% 2007 .06%, disappears after 2007
13) Income Tax Rate (Federal and Provincial): 2005 34.12%, 2006 34.12%, 2007 31.0%, 2008 30.0%, 2009 28.5%, after 2009 27.0%
14) Annual Energy Production based on Niagara River flows from 1926 to 2002 to determine diversion flows
15) in 2017 a scheduled outage on Niagara's canal is expected to occur resulting in increased energy produciton for the tunnel
16) LUEC escalates at CPI
17) PPA - 20% of PPA escalates at CPI
18) Total NPV of costs equals total NPV of LUEC revenues over 90 year life
19) Total NPV of costs equals total NPV of PPA revenues over 90 year life

LUEC

				2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Year				2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Production	(TWh)		(a)	-	-	-	-	-	-	-	-	-	1.6	1.6	1.6	2.7	1.6	1.6
Yearly Escalation (CPI)	(%)			1.80%	1.60%	1.80%	1.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009								1.000	1.020	1.040	1.061	1.082	1.104	1.126	1.149	1.172	1.195	1.219
LUEC Rate (escalated)	(¢/kWh)	6.8	(b)					6.8	6.9	7.1	7.2	7.4	7.5	7.7	7.8	8.0	8.1	8.3
Yearly Revenue	($M)		(c) = (a)*(b)					0.0	0.0	0.0	0.0	0.0	117.2	119.5	121.9	212.1	126.9	129.4
Discount Rate	(%)			7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor			(d)	1.000	0.935	0.874	0.816	0.763	0.713	0.666	0.623	0.582	0.544	0.508	0.475	0.444	0.415	0.388
(1 - combined income tax rate)			(e)	65.9%	65.9%	69.0%	70.0%	71.5%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)			(f) = (c) * (d) * (e)	1009.8									46.5	44.4	42.3	68.7	38.4	36.6

PPA

					2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Year					2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Production	(TWh)			(a)	-	-	-	-	-	-	-	-	-	1.6	1.6	1.6	2.7	1.6	1.6
Yearly Escalation (CPI)	(%)				1.80%	1.60%	1.80%	1.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	9.6	20%											1.9	2.0	2.0	2.0	2.1	2.1
	(¢/kWh)		80%											7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)			(b)										9.6	9.6	9.7	9.7	9.8	9.8
Yearly Revenue	($M)			(c) = (a)*(b)										149.7	150.3	150.9	258.3	152.1	152.8
Discount Rate	(%)				7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor				(d)	1.000	0.935	0.874	0.816	0.763	0.713	0.666	0.623	0.582	0.544	0.508	0.475	0.444	0.415	0.388
(1 - combined income tax rate)				(e)	65.9%	65.9%	69.0%	70.0%	71.5%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)				(f) = (c) * (d) * (e)	1009.8									59.4	55.8	52.3	83.7	46.1	43.2

Costs - Present Value

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Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:
1) PV date July 1, 2005
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3) Discount Rate 7%
4) Total Project cost of $1.6B (includes $286.6M of Interest During Constru
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7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
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LUEC

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		1.243	1.268	1.294	1.319	1.346	1.373	1.400	1.428	1.457	1.486	1.516	1.546	1.577	1.608	1.641	1.673	1.707	1.741	1.776	1.811	1.848
LUEC Rate (escalated)	(¢/kWh)	8.5	8.6	8.8	9.0	9.2	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.7	10.9	11.2	11.4	11.6	11.8	12.1	12.3	12.6
Yearly Revenue	($M)	132.0	134.6	137.3	140.1	142.9	145.7	148.6	151.6	154.6	157.7	160.9	164.1	167.4	170.7	174.2	177.6	181.2	184.8	188.5	192.3	196.1
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.362	0.339	0.316	0.296	0.276	0.258	0.241	0.226	0.211	0.197	0.184	0.172	0.161	0.150	0.140	0.131	0.123	0.115	0.107	0.100	0.094
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		34.9	33.3	31.7	30.2	28.8	27.5	26.2	25.0	23.8	22.7	21.6	20.6	19.6	18.7	17.9	17.0	16.2	15.5	14.7	14.0	13.4

PPA

Year		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.9	2.9	3.0	3.0	3.1	3.1	3.2
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5	10.6	10.6	10.7	10.8	10.8	10.9
Yearly Revenue	($M)	153.5	154.1	154.8	155.5	156.2	157.0	157.7	158.5	159.2	160.0	160.8	161.7	162.5	163.4	164.2	165.1	166.0	166.9	167.9	168.9	169.8
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.362	0.339	0.316	0.296	0.276	0.258	0.241	0.226	0.211	0.197	0.184	0.172	0.161	0.150	0.140	0.131	0.123	0.115	0.107	0.100	0.094
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		40.6	38.1	35.8	33.6	31.5	29.6	27.8	26.1	24.5	23.0	21.6	20.3	19.1	17.9	16.8	15.8	14.9	14.0	13.1	12.3	11.6

Costs - Present Value

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Attachemnt 2

Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:
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LUEC

		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Year		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		1.885	1.922	1.961	2.000	2.040	2.081	2.122	2.165	2.208	2.252	2.297	2.343	2.390	2.438	2.487	2.536	2.587	2.639	2.692	2.745	2.800
LUEC Rate (escalated)	(¢/kWh)	12.8	13.1	13.3	13.6	13.9	14.2	14.4	14.7	15.0	15.3	15.6	15.9	16.3	16.6	16.9	17.3	17.6	18.0	18.3	18.7	19.1
Yearly Revenue	($M)	200.1	204.1	208.1	212.3	216.5	220.9	225.3	229.8	234.4	239.1	243.9	248.7	253.7	258.8	264.0	269.2	274.6	280.1	285.7	291.4	297.3
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.087	0.082	0.076	0.071	0.067	0.062	0.058	0.054	0.051	0.048	0.044	0.042	0.039	0.036	0.034	0.032	0.030	0.028	0.026	0.024	0.023
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		12.8	12.2	11.6	11.1	10.5	10.0	9.6	9.1	8.7	8.3	7.9	7.5	7.2	6.8	6.5	6.2	5.9	5.7	5.4	5.1	4.9

PPA

Year		2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.2	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	11.0	11.0	11.1	11.2	11.2	11.3	11.4	11.4	11.5	11.6	11.7	11.7	11.8	11.9	12.0	12.1	12.2	12.3	12.4	12.4	12.5
Yearly Revenue	($M)	170.8	171.9	172.9	174.0	175.1	176.2	177.3	178.4	179.6	180.8	182.0	183.3	184.5	185.8	187.2	188.5	189.9	191.3	192.7	194.2	195.7
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.087	0.082	0.076	0.071	0.067	0.062	0.058	0.054	0.051	0.048	0.044	0.042	0.039	0.036	0.034	0.032	0.030	0.028	0.026	0.024	0.023
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		10.9	10.2	9.6	9.1	8.5	8.0	7.5	7.1	6.7	6.3	5.9	5.6	5.2	4.9	4.6	4.4	4.1	3.9	3.6	3.4	3.2

Costs - Present Value

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Capital Costs	($M)
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Capital Tax	($M)
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NPV - Total (2005$)	($M)

Assumptions:

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LUEC

		2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		2.856	2.913	2.972	3.031	3.092	3.154	3.217	3.281	3.347	3.414	3.482	3.551	3.623	3.695	3.769	3.844	3.921	4.000	4.080	4.161	4.244
LUEC Rate (escalated)	(¢/kWh)	19.4	19.8	20.2	20.6	21.0	21.5	21.9	22.3	22.8	23.2	23.7	24.2	24.7	25.1	25.6	26.2	26.7	27.2	27.8	28.3	28.9
Yearly Revenue	($M)	303.2	309.3	315.5	321.8	328.2	334.8	341.5	348.3	355.3	362.4	369.6	377.0	384.5	392.2	400.1	408.1	416.2	424.6	433.1	441.7	450.6
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.021	0.020	0.018	0.017	0.016	0.015	0.014	0.013	0.012	0.011	0.011	0.010	0.009	0.009	0.008	0.008	0.007	0.007	0.006	0.006	0.005
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		4.7	4.5	4.2	4.0	3.9	3.7	3.5	3.3	3.2	3.0	2.9	2.8	2.6	2.5	2.4	2.3	2.2	2.1	2.0	1.9	1.8

PPA

Year		2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080	2081	2082
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.1	6.2	6.3	6.4	6.6	6.7	6.8	7.0	7.1	7.2	7.4
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	12.6	12.7	12.8	12.9	13.0	13.2	13.3	13.4	13.5	13.6	13.7	13.8	14.0	14.1	14.2	14.4	14.5	14.6	14.8	14.9	15.1
Yearly Revenue	($M)	197.2	198.7	200.3	201.9	203.6	205.2	207.0	208.7	210.5	212.3	214.1	216.0	218.0	219.9	221.9	224.0	226.1	228.2	230.4	232.6	234.8
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.021	0.020	0.018	0.017	0.016	0.015	0.014	0.013	0.012	0.011	0.011	0.010	0.009	0.009	0.008	0.008	0.007	0.007	0.006	0.006	0.005
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		3.0	2.9	2.7	2.5	2.4	2.3	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.2	1.1	1.0	1.0	0.9

Costs - Present Value

Capital Costs	($M)
Operating Costs	
GRC	($M)
OM&A	($M)
Capital Tax	($M)
Large Corporation Tax	($M)
NPV - Total (2005$)	($M)

Assumptions:
1) PV date July 1, 2005
2) Operating cash flows assumed to occur in June of each year
3) Discount Rate 7%
4) Total Project cost of $1.6B (includes $286.6M of Interest During Constru
5) 100% assigned to Capital Cost Allowance (CCA) Class 1 which includes "D
6) Capital costs include working capital requirements which has been calcu
   a) on average revenues paid to OPG based on a 37 day lag
   b) on average OPG pays OM&A based on a 14 day lag
   c) on average GRC is paid immediately, 0 day lag
7) 10 year GRC holiday starting upon COD
8) GRC property tax rate of 26.5% and GRC water rental rate of 9.5%
9) GRC cost based on $40/MWh escalating at 2% starting 2014
10) OM&A costs of $.11M (2005$M/year) escalated by CPI
11) Capital Tax Rate: 2005 .3%, 2006 .3%, 2007 .3%, 2008 .3%, 2009 .23%, 20
12) Large Corporation Tax Rate: 2005 .18%, 2006 .13% 2007 .06%, disappear
13) Income Tax Rate (Federal and Provincial): 2005 34.12%, 2006 34.12%, 20
14) Annual Energy Production based on Niagara River flows from 1926 to 20
15) in 2017 a scheduled outage on Niagara's canal is expected to occur resul
16) LUEC escalates at CPI
17) PPA - 20% of PPA escalates at CPI
18) Total NPV of costs equals total NPV of LUEC revenues over 90 year life
19) Total NPV of costs equals total NPV of PPA revenues over 90 year life

LUEC

		2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	2100	2101	2102	2103
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Escalation Rate from 2009		4.329	4.416	4.504	4.594	4.686	4.780	4.875	4.973	5.072	5.174	5.277	5.383	5.491	5.600	5.712	5.827	5.943	6.062	6.183	6.307	6.433
LUEC Rate (escalated)	(¢/kWh)	29.5	30.0	30.6	31.3	31.9	32.5	33.2	33.8	34.5	35.2	35.9	36.6	37.4	38.1	38.9	39.6	40.4	41.3	42.1	42.9	43.8
Yearly Revenue	($M)	459.6	468.8	478.1	487.7	497.4	507.4	517.5	527.9	538.5	549.2	560.2	571.4	582.8	594.5	606.4	618.5	630.9	643.5	656.4	669.5	682.9
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.005	0.005	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		1.7	1.6	1.6	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7

PPA

		2083	2084	2085	2086	2087	2088	2089	2090	2091	2092	2093	2094	2095	2096	2097	2098	2099	2100	2101	2102	2103
Energy Production	(TWh)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Yearly Escalation (CPI)	(%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
PPA Rate (escalated)	(¢/kWh)	7.5	7.7	7.8	8.0	8.1	8.3	8.5	8.6	8.8	9.0	9.2	9.4	9.5	9.7	9.9	10.1	10.3	10.5	10.7	11.0	11.2
	(¢/kWh)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
	(¢/kWh)	15.2	15.4	15.5	15.7	15.8	16.0	16.1	16.3	16.5	16.7	16.8	17.0	17.2	17.4	17.6	17.8	18.0	18.2	18.4	18.6	18.9
Yearly Revenue	($M)	237.1	239.5	241.9	244.3	246.8	249.3	251.9	254.6	257.3	260.0	262.8	265.7	268.6	271.6	274.6	277.7	280.9	284.1	287.4	290.7	294.2
Discount Rate	(%)	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Annual Discount Factor		0.005	0.005	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001
(1 - combined income tax rate)		73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%	73.0%
NPV - LUEC Revenue (sum all years)		0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3

SEC Interrogatory #045

Ref: Ex. D1-T1-S2, Attachment 2 - DeCew Falls

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 3. Please advise whether the option of sale of the facility was considered, and if not what barriers made that option impossible.

b) P. 4. Please confirm that G7 came in service in July 2010. Please confirm that G8 is on schedule to be in service in August 2010.

Response

a) The sale of DeCew Falls I Generating Station was not considered because it would be inconsistent with the Shareholder Agreement and good business practice. The Shareholder Agreement states: "OPG will seek to expand, develop and/or improve its hydroelectric capacity." Further, the Life Cycle Plan completed in 2009 indicates the station is economic, and its operation is integrated with the DeCew Falls II Generating Station.

b) The construction for Units G7 and G8 penstocks is expected to be completed by the end of 2010. Units G7 and G8 in-services dates will be in early 2011. As described below, the delayed in-service is due to the timing of the contract award, and unforeseen design and construction problems. However, OPG expects that the project contingency is sufficient to complete this project within the approved release amount of $10.5M.

   The original schedule targeted a contract award date of September 30, 2009. The Business Case Summary was approved on October 19, 2009 and final contract award did not occur until November 24, 2009.

   Discovery work during construction, due to unforeseen site conditions for the upper, middle, and powerhouse thrust blocks, resulted in additional design and construction costs. To insure the stability of the penstocks, the thrust blocks needed to be redesigned to make them larger. The additional time to re-engineer, excavate and construct the thrust blocks resulted in additional costs and an extension to the project schedule.

SEC Interrogatory #046

Ref: Ex. D1-T1-S2, Attachment 3 (Saunders)

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

(a) P. 3. Please confirm that this project achieves a security benefit, but no financial benefit or future cost savings.

(b) P. 3. Please advise the total cost of the generator controls. Please advise whether there are any financial benefits or future cost savings associated with that part of the project. Please advise whether there was a separate business case summary for that part of the project, and if so provide that summary.

(c) P. 4. Please confirm that a similar project has been or will be undertaken on the New York side of the power complex. If that is not the case, please advise the reasons why the need for this work would be different in New York than in Ontario.

(d) P. 5. Please confirm that the project was completed in January 2010.

Response

a) This project does achieve a security benefit – implementing the “air gap” solution was necessary to satisfy the North American Electric Reliability Corporation’s Critical Infrastructure Protection requirements by the end of 2009. However, the primary objectives for this project were to replace the generator and transformer protections and controls to sustain reliable generation. The investment was required to bring the generator and transformer protections and controls up to current standards. Protecting this valuable asset and ensuring the station continues to operate reliably will provide financial benefits well into the future.

b) The cost of the generator controls is estimated to be approximately $7M based on the quotes that were obtained from suppliers during the developmental phase release. Protecting the assets will avoid equipment damage and the associated repair costs and lost generation opportunities. A separate business case for the controls was not prepared.

c) New York Power Authority’s investment strategy is commercially sensitive information that OPG is not privy to.

d) This project is scheduled for completion in 2012. It remains on schedule and on budget.

SEC Interrogatory #047
(NON-CONFIDENTIAL VERSION)

Ref: Ex. D1-T1-S2, Attachment 4 (Sir Adam Beck I Generating Station Unit G9 Rehabilitation)

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 2. Please confirm that the increase in capacity of 10 MW and the increase in energy of 60.8 Gwh implies a capacity factor of 70% for the additional capacity. Please disaggregate the energy into incremental energy from the existing capacity level, and incremental energy as a result of the additional MW, and show the capacity factor of the additional 10 MW of peaking resource.

b) P. 6. Please provide the full financial evaluation.

Response

a) No, a 70 per cent capacity factor is not implied for an incremental increase in capacity of 10 MW and incremental energy of 60.8 GWh. To clarify, the 10 MW increase is relative to the existing, end-of-life 50.8 MW generating unit, and the energy production is relative to operating the Sir Adam Beck Generating Station complex without unit G9. The incremental costs associated with installing an upgraded unit rated at 61.6 MW vs. installing a like-for-like 50.8 MW unit were small. Therefore, a financial evaluation was not completed and the incremental energy production and related capacity factors were not estimated for the 50.8 MW unit option.

b) The financial evaluation is attached as Attachment 1 with the commercially sensitive System Economic Values redacted.

Spreadsheet for Calculation of Station NPV, LUEC, and Other Values

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	Plant ID	SAB1 G9 Rehabilitation (Incremental)																	
2	Asset Designation		0	1 for regulated, 0 non-regulated asset															
3	Price Cap for Regulated Asset		NA	Insert Price if not $37.9/MWh															
4	I/S Date		2011																
5	Assumed Life/Study Peiod		50 yrs																
6	Peaking Capacity / MCR		10	61.6															
7	Annual Generation		61 GWh			For determination of the property tax rate													
8		(Existing Generation)				Rate Block	GWh Block	Cumulative	Extg + Inc	Existing GW	Inc GWh								
9	Water Rental		9.50%			2.5%	<50	50	50	0	50								
10	Property Tax		26.50%			4.5%	50 - 400	400	11	0	11								
11	GRC Tax Holiday		0 yrs			6.0%	400-700	700	0	0	0								
12	WACC		7.0%			26.5%	700+	700+	0	0	0								
13	Corp. Tax Rate		27.00%																
14																			
15							2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
16								1	2	3	4	5	6	7	8	9	10	11	12
18	System Economic Values (2008$)		1	1 for Base, 2 Low and 3 High															
19			1	1 to include capacity credit; 0 to exclude															
20	Cost/Price of Power ($/MW)							[redacted]											
21	Winter Peak Energy Price($/MWh)																		
22	Winter Off-Peak Energy Price($/MWh)																		
23	Summer Peak Energy Price($/MWh)																		
24	Summer Off-Peak Energy Price($/MWh)																		
25																			
28	Revenue																		
29	Capacity (MW)					10		0	0	0	10	10	10	10	10	10	10	10	10
30	Annual Energy (GWh)				100%	61		0	0	0	61	61	61	61	61	61	61	61	61
31	Winter Peak Energy (GWh)			39.456	65%			0	0	0	39	39	39	39	39	39	39	39	39
32	Winter Off-Peak Energy (GWh)			1.072	2%			0	0	0	1	1	1	1	1	1	1	1	1
33	Summer Peak Energy (GWh)			15.923	26%			0	0	0	16	16	16	16	16	16	16	16	16
34	Summer Off-Peak Energy (GWh)			4.394	7%			0	0	0	4	4	4	4	4	4	4	4	4
35																			
36	Revenue from Generation (in 2008$)							0	0	0	3,938	3,957	4,007	4,497	5,027	5,566	5,719	5,821	5,821
37	Revenue from Generation (esc. k$)							0	0	0	4,125	4,198	4,315	4,920	5,598	6,313	6,610	6,857	6,990
38	Other Revenue AGC + reactive support & voltage control																		
39	Total Revenue (Esc k$)							0	0	0	4,125	4,198	4,315	4,920	5,598	6,313	6,610	6,857	6,990
40																			
41	Capital Costs (see CCA descriptions below)																		
42	Capital Additions (Esc k$) CCA Class 1 (4%)																		
43	Capital Additions (Esc k$) CCA Class 1** (6%)																		
44	Capital Additions (Esc k$) CCA Class 17 (8%)							1,975	14,980	13,013									
45	Capital Additions (Esc k$) CCA Class 43.1 (30%)																		
46	Capital Additions (Esc k$) CCA Class 8 (20%)																		
47	Total Capital Costs For Year (esc. K$) (no interest)							1,975	14,980	13,013	0	0	0	0	0	0	0	0	0
48																			
49	Operating & Other Costs (esc k$)																		
50	Water Rental (40 $/MWh price assumed thru 2012)							0	0	0	231	231	231	467	532	600	628	651	664
51	OM&A																		
52	- Base (property taxes not included)							0	0	0	0	0	0	0	0	0	0	0	0
53	- Non-Standard																		
54	- GRC Property Tax/Graduated Component (40 $/MWh price assumed thru 2012)							0	0	0	645	645	645	1,304	1,483	1,673	1,752	1,817	1,852
55	- Other Costs							0	0	0	0	0	0	0	0	0	0	0	0
56	Tot. Operating & Other Costs							0	0	0	876	876	876	1,771	2,015	2,273	2,380	2,469	2,516
57	Net Income Before Taxes(Taxable Income)							0	0	0	3,249	3,322	3,438	3,149	3,582	4,040	4,231	4,388	4,474
58	Income Taxes							0	0	0	926	897	928	850	967	1,091	1,142	1,185	1,208
59	Add: Tax Shield From CCA							25	233	543	623	543	500	460	423	389	358	329	303
60	Net Income after All Taxes							25	233	543	2,946	2,968	3,010	2,758	3,038	3,338	3,446	3,533	3,569
61																			
62	Annual Cash Flow							-1,950	-14,747	-12,470	2,946	2,968	3,010	2,758	3,038	3,338	3,446	3,533	3,569
63	NPV of Cash Flow					17,617		-1,950	-13,782	-10,892	2,405	2,265	2,146	1,838	1,892	1,943	1,875	1,796	1,695
64	Cumulative NPV of Cash Flows			checking...		17615		-1,950	-15,733	-26,624	-24,219	-21,955	-19,809	-17,971	-16,079	-14,136	-12,262	-10,466	-8,770
65	PV Energy (GWh)					720													
66	PV Of All Costs (2008$k)					47233													
67	LUEC (2008$/MWh)					66	as compared to avg. price of			$90 /MWh									
68	IRR					11.0%													
69	Payback Period					16 yrs		0	0	0	1	1	1	1	1	1	1	1	1
72																			
73	Financial Factors																		
74	Federal&Provincial Tax Rate For Generator Of Electricity							31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
75	PV Factor							1.00	0.93	0.87	0.82	0.76	0.71	0.67	0.62	0.58	0.54	0.51	0.48
76	CPI, %change							1.9%	2.2%	2.1%	2.1%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
77	CPI Index							1.00	1.02	1.04	1.06	1.09	1.11	1.13	1.15	1.18	1.20	1.22	1.25
78	GDP Deflator, %change							2.0%	1.7%	1.6%	1.4%	1.3%	1.5%	1.6%	1.8%	1.9%	1.9%	1.9%	1.9%
79	GDP Index							1.00	1.02	1.03	1.05	1.06	1.08	1.09	1.11	1.13	1.16	1.18	1.20
80	OM&A Escalator, %change							3.6%	4.3%	4.4%	3.9%	4.1%	4.5%	4.5%	4.4%	4.7%	5.1%	5.3%	5.4%
81	OM&A Index							1.00	1.04	1.09	1.13	1.18	1.23	1.28	1.34	1.40	1.48	1.55	1.64
82	Capital Escalator, % change							-2.9%	0.7%	1.2%	1.2%	1.9%	2.0%	1.6%	1.4%	1.6%	1.4%	1.3%	1.6%
83	Capital Index							1.00	1.01	1.02	1.03	1.05	1.07	1.09	1.10	1.12	1.14	1.15	1.17
84																			
85																			
86	CCA Calculation																		
87																			
88	Opening Balance - UCC																		
89	Class 1 - Generating Equip-Bldgs & Other Structures							0	0	0	0	0	0	0	0	0	0	0	0
90	Class 1** - New non-residential buildings							0	0	0	0	0	0	0	0	0	0	0	0
91	Class 17 - Generating Equp acquired after Feb. 2000							0	-1,896	-16,125	-27,328	-25,141	-23,130	-21,280	-19,577	-18,011	-16,570	-15,245	-14,025
92	Class 43.1 - Small Hydro Electric							0	0	0	0	0	0	0	0	0	0	0	0
93	Class 8 - Miscellaneous Equipment							0	0	0	0	0	0	0	0	0	0	0	0
94								0	-1,896	-16,125	-27,328	-25,141	-23,130	-21,280	-19,577	-18,011	-16,570	-15,245	-14,025
95	In-service additions																		
96	Class 1 - Generating Equip-Bldgs & Other Structures							0	0	0	0	0	0	0	0	0	0	0	0
97	Class 1** - New non-residential buildings							0	0	0	0	0	0	0	0	0	0	0	0
98	Class 17 - Generating Equp acquired after Feb. 2000							-1,975	-14,980	-13,013	0	0	0	0	0	0	0	0	0
99	Class 43.1 - Small Hydro Electric							0	0	0	0	0	0	0	0	0	0	0	0
100	Class 8 - Miscellaneous Equipment							0	0	0	0	0	0	0	0	0	0	0	0
101								-1,975	-14,980	-13,013	0	0	0	0	0	0	0	0	0
102	CCA calculation:																		
103	Class 1 - Generating Equip-Bldgs & Other Structures				4%			0	0	0	0	0	0	0	0	0	0	0	0
104	Class 1** - New non-residential buildings				6%			0	0	0	0	0	0	0	0	0	0	0	0
105	Class 17 - Generating Equp acquired after Feb. 2000				8%			-79	-751	-1,811	-2,186	-2,011	-1,850	-1,702	-1,566	-1,441	-1,326	-1,220	-1,122
106	Class 43.1 - Small Hydro Electric				30%			0	0	0	0	0	0	0	0	0	0	0	0
107	Class 8 - Miscellaneous Equipment				20%			0	0	0	0	0	0	0	0	0	0	0	0
108								-79	-751	-1,811	-2,186	-2,011	-1,850	-1,702	-1,566	-1,441	-1,326	-1,220	-1,122
109	Ending balance:																		
110	Class 1 - Generating Equip-Bldgs & Other Structures							0	0	0	0	0	0	0	0	0	0	0	0
111	Class 1** - New non-residential buildings							0	0	0	0	0	0	0	0	0	0	0	0
112	Class 17 - Generating Equp acquired after Feb. 2000							-1,896	-16,125	-27,328	-25,141	-23,130	-21,280	-19,577	-18,011	-16,570	-15,245	-14,025	-12,903
113	Class 43.1 - Small Hydro Electric							0	0	0	0	0	0	0	0	0	0	0	0
114	Class 8 - Miscellaneous Equipment							0	0	0	0	0	0	0	0	0	0	0	0
115								-1,896	-16,125	-27,328	-25,141	-23,130	-21,280	-19,577	-18,011	-16,570	-15,245	-14,025	-12,903
116	Tax Shield (tax rate) x CCA							25	233	543	623	543	500	460	423	389	358	329	303

	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE
15	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
16	13	14	15	16	17	18	19	20	21	22	23	24
29	10	10	10	10	10	10	10	10	10	10	10	10
30	61	61	61	61	61	61	61	61	61	61	61	61
31	39	39	39	39	39	39	39	39	39	39	39	39
32	1	1	1	1	1	1	1	1	1	1	1	1
33	16	16	16	16	16	16	16	16	16	16	16	16
34	4	4	4	4	4	4	4	4	4	4	4	4
36	5,769	5,738	5,781	5,803	5,843	5,882	5,959	5,999	5,999	5,999	5,999	5,999
37	7,064	7,160	7,354	7,527	7,729	7,933	8,192	8,405	8,567	8,731	8,899	9,070
39	7,064	7,160	7,354	7,527	7,729	7,933	8,192	8,405	8,567	8,731	8,899	9,070
47	0	0	0	0	0	0	0	0	0	0	0	0
50	671	680	699	715	734	754	778	799	814	829	845	862
52	0	0	0	0	0	0	0	0	0	0	0	0
54	1,872	1,898	1,949	1,995	2,048	2,102	2,171	2,227	2,270	2,314	2,358	2,404
55	0	0	0	0	0	0	0	0	0	0	0	0
56	2,543	2,578	2,648	2,710	2,782	2,856	2,949	3,026	3,084	3,143	3,204	3,265
57	4,521	4,583	4,707	4,817	4,947	5,077	5,243	5,379	5,483	5,588	5,695	5,805
58	1,221	1,237	1,271	1,301	1,336	1,371	1,416	1,452	1,480	1,509	1,538	1,567
59	279	256	236	217	200	184	169	155	143	132	121	111
60	3,579	3,602	3,672	3,734	3,811	3,890	3,997	4,082	4,145	4,211	4,279	4,349
62	3,579	3,602	3,672	3,734	3,811	3,890	3,997	4,082	4,145	4,211	4,279	4,349
63	1,589	1,495	1,424	1,353	1,291	1,231	1,182	1,129	1,071	1,017	966	917
64	-7,181	-5,687	-4,263	-2,909	-1,619	-387	795	1,924	2,995	4,012	4,978	5,896
69	1	1	1	1	1	1	0	0	0	0	0	0
74	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
75	0.44	0.41	0.39	0.36	0.34	0.32	0.30	0.28	0.26	0.24	0.23	0.21
76	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
77	1.27	1.30	1.32	1.35	1.38	1.40	1.43	1.46	1.49	1.52	1.55	1.58
78	2.0%	1.9%	1.9%	2.0%	2.0%	2.0%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
79	1.22	1.25	1.27	1.30	1.32	1.35	1.37	1.40	1.43	1.46	1.48	1.51
80	5.5%	5.4%	5.3%	5.3%	5.3%	5.3%	5.2%	5.0%	5.0%	5.0%	5.0%	5.0%
81	1.73	1.82	1.92	2.02	2.13	2.24	2.35	2.47	2.60	2.73	2.87	3.01
82	1.6%	1.6%	1.7%	1.8%	1.9%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
83	1.19	1.21	1.23	1.25	1.27	1.30	1.32	1.34	1.37	1.39	1.42	1.44
89	0	0	0	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0	0	0	0
91	-12,903	-11,871	-10,921	-10,047	-9,244	-8,504	-7,824	-7,198	-6,622	-6,092	-5,605	-5,157
92	0	0	0	0	0	0	0	0	0	0	0	0
93	0	0	0	0	0	0	0	0	0	0	0	0
94	-12,903	-11,871	-10,921	-10,047	-9,244	-8,504	-7,824	-7,198	-6,622	-6,092	-5,605	-5,157
96	0	0	0	0	0	0	0	0	0	0	0	0
97	0	0	0	0	0	0	0	0	0	0	0	0
98	0	0	0	0	0	0	0	0	0	0	0	0
99	0	0	0	0	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0	0	0	0	0
101	0	0	0	0	0	0	0	0	0	0	0	0
103	0	0	0	0	0	0	0	0	0	0	0	0
104	0	0	0	0	0	0	0	0	0	0	0	0
105	-1,032	-950	-874	-804	-739	-680	-626	-576	-530	-487	-448	-413
106	0	0	0	0	0	0	0	0	0	0	0	0
107	0	0	0	0	0	0	0	0	0	0	0	0
108	-1,032	-950	-874	-804	-739	-680	-626	-576	-530	-487	-448	-413
110	0	0	0	0	0	0	0	0	0	0	0	0
111	0	0	0	0	0	0	0	0	0	0	0	0
112	-11,871	-10,921	-10,047	-9,244	-8,504	-7,824	-7,198	-6,622	-6,092	-5,605	-5,157	-4,744
113	0	0	0	0	0	0	0	0	0	0	0	0
114	0	0	0	0	0	0	0	0	0	0	0	0
115	-11,871	-10,921	-10,047	-9,244	-8,504	-7,824	-7,198	-6,622	-6,092	-5,605	-5,157	-4,744
116	279	256	236	217	200	184	169	155	143	132	121	111

	AF	AG	AH	AI	AJ	AK	AL	AM	AN
15	2032	2033	2034	2035	2036	2037	2038	2039	2040
16	25	26	27	28	29	30	31	32	33
29	10	10	10	10	10	10	10	10	10
30	61	61	61	61	61	61	61	61	61
31	39	39	39	39	39	39	39	39	39
32	1	1	1	1	1	1	1	1	1
33	16	16	16	16	0	16	16	16	16
34	4	4	4	4	0	4	4	4	4
36	5,999	5,999	5,999	5,999	4,331	5,999	5,999	5,999	5,999
37	9,244	9,422	9,603	9,788	7,202	10,167	10,363	10,562	10,765
39	9,244	9,422	9,603	9,788	7,202	10,167	10,363	10,562	10,765
47	0	0	0	0	0	0	0	0	0
50	878	895	912	930	684	966	984	1,003	1,023
52	0	0	0	0	0	0	0	0	0
53					16,290				
54	2,450	2,497	2,545	2,594	1,908	2,694	2,746	2,799	2,853
55	0	0	0	0	0	0	0	0	0
56	3,328	3,392	3,457	3,524	18,883	3,660	3,731	3,802	3,875
57	5,916	6,030	6,146	6,264	-11,681	6,507	6,632	6,759	6,889
58	1,597	1,628	1,659	1,691	-3,154	1,757	1,791	1,825	1,860
59	102	94	87	80	73	68	62	57	53
60	4,421	4,496	4,573	4,653	-8,454	4,818	4,904	4,992	5,082
62	4,421	4,496	4,573	4,653	-8,454	4,818	4,904	4,992	5,082
63	872	828	787	749	-1,271	677	644	613	583
64	6,767	7,596	8,383	9,132	7,860	8,538	9,182	9,795	10,378
69	0	0	0	0	0	0	0	0	0
74	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
75	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.12	0.11
76	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
77	1.61	1.65	1.68	1.71	1.75	1.78	1.82	1.85	1.89
78	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%
79	1.54	1.57	1.60	1.63	1.66	1.69	1.73	1.76	1.79
80	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
81	3.16	3.32	3.49	3.67	3.85	4.05	4.25	4.46	4.69
82	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
83	1.47	1.50	1.52	1.55	1.58	1.61	1.64	1.67	1.70
89	0	0	0	0	0	0	0	0	0
90	0	0	0	0	0	0	0	0	0
91	-4,744	-4,364	-4,015	-3,694	-3,399	-3,127	-2,877	-2,646	-2,435
92	0	0	0	0	0	0	0	0	0
93	0	0	0	0	0	0	0	0	0
94	-4,744	-4,364	-4,015	-3,694	-3,399	-3,127	-2,877	-2,646	-2,435
96	0	0	0	0	0	0	0	0	0
97	0	0	0	0	0	0	0	0	0
98	0	0	0	0	0	0	0	0	0
99	0	0	0	0	0	0	0	0	0
100	0	0	0	0	0	0	0	0	0
101	0	0	0	0	0	0	0	0	0
103	0	0	0	0	0	0	0	0	0
104	0	0	0	0	0	0	0	0	0
105	-380	-349	-321	-296	-272	-250	-230	-212	-195
106	0	0	0	0	0	0	0	0	0
107	0	0	0	0	0	0	0	0	0
108	-380	-349	-321	-296	-272	-250	-230	-212	-195
110	0	0	0	0	0	0	0	0	0
111	0	0	0	0	0	0	0	0	0
112	-4,364	-4,015	-3,694	-3,399	-3,127	-2,877	-2,646	-2,435	-2,240
113	0	0	0	0	0	0	0	0	0
114	0	0	0	0	0	0	0	0	0
115	-4,364	-4,015	-3,694	-3,399	-3,127	-2,877	-2,646	-2,435	-2,240
116	102	94	87	80	73	68	62	57	53

SEC Interrogatory #048

Ref: Ex. F1-T1-S1, Attachment 1 - Hydroelectric Business Plan

Issue Number: 4.2
Issue: Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

Interrogatory

a) P. 3. Please confirm that, based on current information, the Applicant has been underinvesting in the "re-investment" component of hydroelectric for the past 10 years. If this is the case, please estimate the amount of underinvestment, and estimate the amount of the spending going forward that can fairly be termed "catch-up" to get the hydroelectric reinvestment levels back to a proper amount.

b) P. 6. Please explain why hydroelectric OM&A and Operations Capital are both forecast to drop from 2011 to 2012.

c) P. 7. Please provide a copy of the business case and related cost/benefit analysis for the Niagara Bridge Divestiture Strategy.

d) P. 7. Please explain in detail the strategy to reduce the labour and payroll burden rates as indicated.

e) P. 9. Please provide a copy of the preliminary review of the expansion of the existing PGS reservoir. Please advise what work is being done on this project in 2011 and 2012.

f) P. 17. Please provide updated tables for Age Distribution and Retirement Eligibility.

g) P. 18. Please describe in detail the "over-hiring" strategy and estimate its cost implications.

h) P. 27. Please explain the 6% increase in Regular Staff from 2009 to 2010.

i) P. 27. Please explain the terminology "contribution margin" and describe how the figure is calculated.

j) P. 33. Please disaggregate the causes for the 1.8% EFOR forecast, and quantify the impact on revenue requirement of the difference between the 1.8% forecast and the 1.5% benchmark.

Response

a) No, the regulated hydroelectric facilities have received and continue to receive appropriate levels of reinvestment based on the Hydroelectric portfolio management system described on page 3 of Ex. F1-T1-S1.

b) The forecast totals for OM&A and Capital on page 6 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. Please refer to Ex. D1-T1-S1, Ex. F1-T2-S2, and Ex. F1-T3-S2 for year-over-year explanations of Capital, Base OM&A, and Project OM&A for the regulated stations.

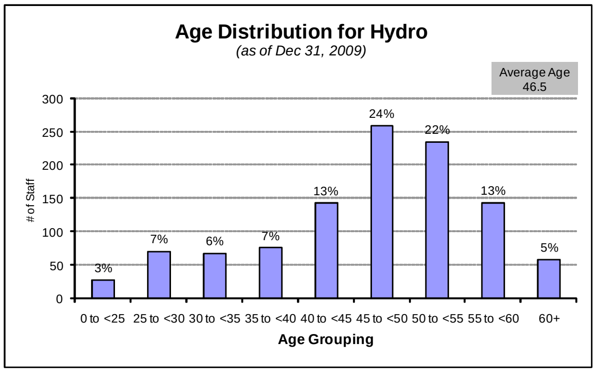
c) OPG does not have a single business case summary ("BCS") prepared for the overall bridge divestiture strategy. Individual BCSs are prepared for each bridge divestiture as each bridge has its own unique agreements, obligations, and asset condition. OPG has ongoing legal obligations related to roadway bridges in the Niagara Region. A strategy has been put in place to divest the bridges to the local municipalities in order to reduce the future costs, liabilities, and risks to OPG. The costs and benefits of this program are described in Ex. F1-T2-S1, page 2, lines 26-30, and in Ex. F1-T2-S2 on pages 2 and 3.

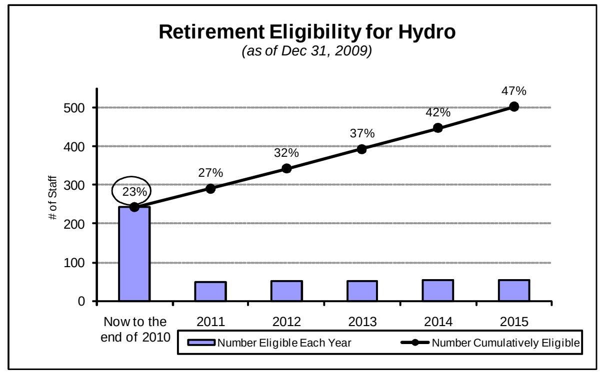
d) A description of labour burdens, along with the related pension and benefits discussion, can be found in sections 6 and 7 of Ex. F4-T3-S1 on Compensation, Wages and Benefits.

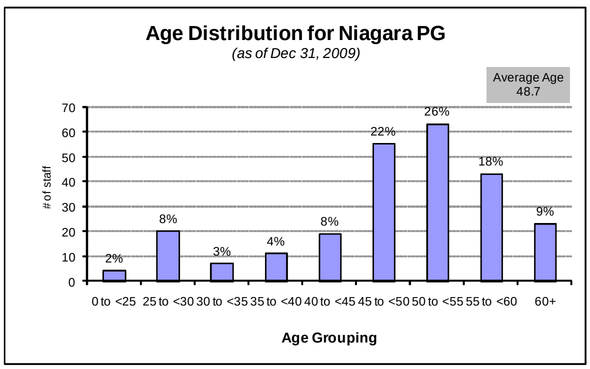
e) The preliminary review report summarizing the expansion options for the reservoir has not been finalized. A draft report has been received from the consultant, Hatch Energy, and is currently being reviewed by OPG's technical staff. The preliminary review report is expected to be completed by the end of 2010.

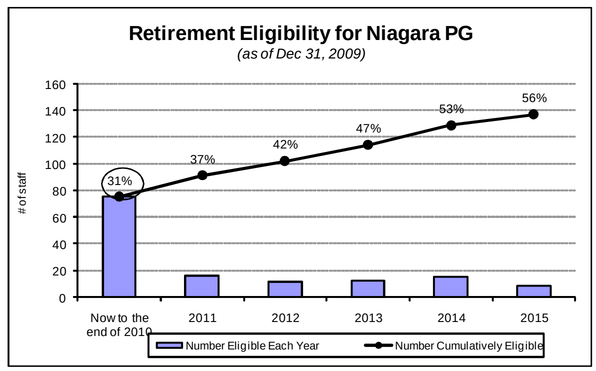
As described in the Board staff interrogatory in Ex. L-1-043, the preliminary review referenced in the Business Plan Presentation considered the following options: expanding the footprint of the reservoir, deepening the reservoir, and increasing the dyke elevation. While the reservoir volume increases under the individual options can be as high as 27 per cent, a combination of options could result in volume increases of over 40 per cent. The next steps include the preparation of cost estimates and geotechnical reviews of the options by third-party experts. If the expansion work proceeds, it will be aligned with the comprehensive remedial work on the present dyke.

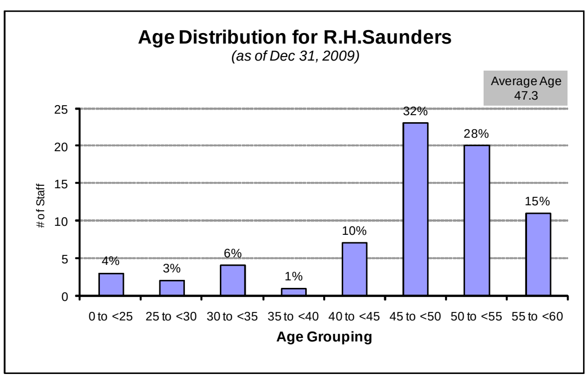
f) Updated Age Distribution and Retirement Eligibility graphs are below.

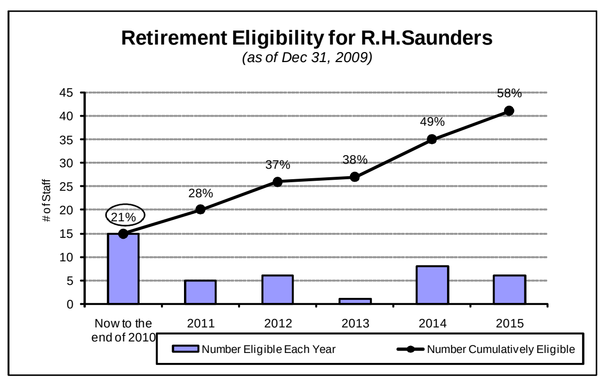












g) Please see responses to Board staff and Energy Probe interrogatories in Ex. L-1-041 and Ex. L-6-004 respectively for a description of the "over-hiring" strategy. In addition to changes in labour rates, staff counts are a significant contributor to the year-over-year changes in total labour costs observed in Ex. F1-T2-S1, Tables 1 and 2.

h) The regular staff Full Time Equivalents ("FTE") for 2009 and 2010 on page 27 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. However, the Hydroelectric business unit total FTEs do include the impact of the hiring strategy described in part g).

i) The contribution margins presented on page 27 of the Hydroelectric Business Plan presentation include unregulated facilities and are therefore not relevant to this rate application. However, contribution margin is defined as the total revenues minus all OM&A, Gross Revenue Charges, and other water rental payments. Taxes and other costs are excluded.

j) A discussion of reliability performance, including station level Equivalent Forced Outage Rate (”EFOR”) data, is included in Ex. F1-T1-S1, Section 3 and 4. By definition, the EFOR measure captures reliability-related forced outages, which are unplanned events. In general, at the low levels of EFOR experienced by OPG’s regulated hydroelectric facilities, forced outages do not have a material impact on revenue requirements because repairs are usually funded by existing Base OM&A budgets.