Board Staff Interrogatory #044

Ref: Ex. F2-T1-S1, Table1

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

Interrogatory

In relation to aggregate Nuclear OM&A Costs, please provide variance explanations for the difference:

a) between 2008 actual and 2008 Board-approved amounts; and
b) between 2009 actual and 2009 Board-approved amounts.

Response

The OEB did not approve aggregate Nuclear OM&A costs in EB-2007-0905. The Board-approved OM&A for 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.

OPG provides budget vs. actual variance explanations for 2008 and 2009, where the budget values are those filed by OPG in EB-2007-0905, as follows:

- Base OM&A – Ex. F2-T2-S2, pages 4-8.
- Project OM&A – Ex. F2-T3-S2, page 2.
- Outage OM&A – Ex. F2-T4-S2, pages 4-6.
- Allocated corporate OM&A – Ex. F3-T1-S2, pages 4-5.
- Asset service fees – Ex. F3-T2-S2, page 2.
- Allocated centrally-held costs – Ex. F4-T4-S2, pages 5-7.

Board Staff Interrogatory #045

Ref: Ex. F2-T2-S1, page 1

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

Interrogatory

The application notes on page 1 *"OPG has made significant operational and cost improvements which have been demonstrated since the previous application: Specifically: 2012 base OM&A costs are to be forecast to be below 2008 actual costs, with cumulative work-driven cost savings of $260M for the 2010 - 2012 period; 2012 regular staff levels are forecast below 2008 levels by 689 staff, while non-regular 17 staff FTEs ("full time equivalents") are reduced by 559*". In A1-T3- S1 (p.4) it notes that these reductions are due to the seven key initiatives as part of the 2010 - 2014 Nuclear Business Plan and other cost control measures explained in Ex. F2-T1-S1. However, based on information provided during the previous OPG payments application process, Board staff expected substantial reductions absent any new cost control measures or initiatives. For example:

- OPG's Reply Argument in the previous case noted *"Staffing levels since 2006 have been under pressure due to changes in work programs for matters such as security, new generation development; Pickering B refurbishment, and the isolation and safe storage of Pickering A units 2 and 3, preparation for vacuum building outages at both Darlington and Pickering and maintenance backlog reductions (Tr. Vol. 5, 3 pages 39-40) … with completion of planned improvement initiatives and as a result of cost containment initiatives outlined in the evidence, total OM&A for nuclear is forecast to decrease in 2009 compared to 2008".*

- OPG's Final Argument also noted: *"For nuclear, the trend reflecting increasing FTE numbers into 2008 is necessary for OPG's planned improvement programs. Subsequent reductions in 2009 are consistent with the completion of these programs (Ex. F2-T2-S1, pages 20-21). For example, Mr. Robinson testified: "…that Darlington and the ops and maintenance area was higher than the benchmark. We went back and looked at that, and we said, yes, that is valid because of the increased resources we were applying to backlog reduction, and we see through the evidence that, over time, those numbers will come down (Tr. Vol. 5, page 14)*."

- In addition, OPG's Nuclear Business Plan also discusses a significant reduction in FTEs and Nuclear OM&A costs due to the discontinuation of an agreement with Bruce Power to provide services.

Based on the above and the completion of the two major vacuum building outages (VBOs) in 2009 and 2010:

a) Were many of the reductions in costs and FTEs expected regardless of the seven key initiatives and other cost control measures identified in this application?

b) Please identify the estimated FTE and cost savings associated with each new initiative as well as each additional new cost saving measure OPG refers to in the application.

c) Further to the above, please reproduce Table 1 in F2-T1-S1 (Operating Costs Summary – Nuclear) up to line 9 (Total OM&A) in the following manner. Exclude the costs associated with the following extraordinary and/or non-recurring items:

- Temporary increase in OM&A costs/FTEs approved by the Board to address the backlog issue
- Isolation and safe storage of Pickering A units 2 and 3 (project now completed)
- Major VBO outage completed for Darlington in 2009 (occurs once every decade)
- Major VBO outage completed for Pickering in 2010 (occurs once every decade)
- Discontinuation of Service Agreements with Bruce Power amounting to $145M in savings for the 2010-2012 period (as identified on page 19 of the Nuclear Business Plan in Attachment 1)
- Pickering Continued Operations
- Darlington Refurbishment

Please show the costs associated with the excluded items shown above as separate line items below the revised Total OM&A at Line #9.

Response

a) It is not possible to determine the savings that would have resulted relative to the last application if the initiatives that form the existing 2010 – 2014 business plan are removed. The business plan underpinning the payment amounts in EB-2007-0905 covered 2008 – 2010 and did not include the years 2011 and 2012.

b) Of the 33 initiatives identified in the business plan, the fleet-wide initiatives contributing to the cost savings are presented in Table 1 along with their forecast savings over the test period. FTE savings were not tracked by initiative. For a summary of FTE reductions over the test period, see Ex. F2-T1-S1, Attachment 1, page 19.

Table 1: OM&A Savings Associated with Fleet-Wide Initiatives ($k)

		OM&A Savings		
Initiative ID	**Initiative Name**	**2011**	**2012**	**Total - Test Period**
Maintenance				
MA-04	Centralized Measurement and Test Equipment	($350)	($350)	($700)
MA-08	Day Based Maintenance	$0	($5,184)	($5,184)
MA-09	Single Source Laundry	($3,000)	($3,000)	($6,000)
Outage				
OU-02	Outage Improvement Strategy	($5,540)	($7,604)	($13,144)
Engineering				
EN-01	Work Order Readiness	($780)	($1,560)	($2,340)
EN-02	Engineering Value for Money	($3,750)	($7,930)	($11,680)
EN-03	Improve Fuel Reliability Index	$30	$30	$60
Equipment Reliability				
ER-02	Improve Preventive Maintenance Program	($30)	($30)	($60)
Industrial Safety				
IS-01	Musculoskeletal Disorder Prevention	$240	$0	$240
IS-02	Safety Behaviours Assessment	$65	$0	$65
IS-04	Constrain Training Qualification	($1,168)	($1,168)	($2,336)
Radiaton Protection				
RP-05	Optimize Reactor Face Shielding	($315)	($565)	($880)
RP-26	Area Mapping	$75	$0	$75
RP-9	Improve Fuel Machine Filtration	$150	$0	$150
Fire Safety				
FS-03 (Revenue)	Offer Fire Training	($100)	($100)	($200)
Training				
TR-04	Initial Authorization Training Program	$2,605	$2,074	$4,679
TR-02	Computer Based Training Increase	($134)	($129)	($263)
TR-06	Outage Improvement Strategy	($354)	($288)	($642)
Financial Performance				
FP-02	Labour Cost Reduction	($1,068)	($1,068)	($2,136)
TOTALS		**($13,424)**	**($26,872)**	**($40,296)**

In addition to the forecast savings from the fleet-wide initiatives, OPG Nuclear has developed divisional and local cost reduction measures. These measures address areas such as contract services, outsourcing, overtime, organizational consolidations, inspection scopes, etc.

As seen in Notes 1 and 2 to Ex. F2-T1-S1, Attachment 1, page 16, the total divisional cost targets are the net of divisional “targeted reductions” and divisional “additional expenditures” (i.e., $36.3M in 2011 and $41.7M in 2012). The combination of fleet-wide initiatives and the divisional / local measures are the basis for achieving these cost reduction targets.

c) See reproduced and modified Ex. F2-T1-S1, Table 1 below.

Table 1

Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A**	1,204.9	1,252.4	1,216.5	1,187.0	1,192.3	1,219.8
2	**Project OM&A**	111.6	134.7	143.7	143.8	135.9	132.2
3	**Outage OM&A**	215.6	196.1	254.8	284.6	214.8	201.1
4	**Subtotal**	1,532.0	1,583.2	1,615.0	1,615.5	1,543.0	1,553.2
5	**Generation Development OM&A**	11.8	34.1	79.6	60.5	5.9	4.5
6	**Allocation of Corporate Costs**	240.7	237.6	233.2	244.1	247.3	250.4
7	**Allocation of Centrally Held Costs**	210.2	132.2	58.8	171.0	199.0	234.3
8	**Asset Service Fee**	33.2	28.8	27.2	24.6	24.1	23.7
9	**Total OM&A**	**2,027.9**	**2,015.9**	**2,013.7**	**2,115.7**	**2,019.4**	**2,066.0**
	Excluded from Total OM&A (line 9 above)						
Note 1	**Temporary Increase for Backlog Issues**			(9.3)	(9.8)	(7.4)	
Note 2	**P2/P3 Isolation and Safe Storage**	(9.5)	(13.5)	(22.5)	(20.6)		
Note 3	**Darlington VBO - 2009**	(0.8)	(8.1)	(35.4)			
Note 3	**Pickering VBO - 2010**		(0.9)	(5.8)	(32.2)		
Note 4	**Discontinuation of Service Ageement with Bruce Power**						
Note 5	**Pickering B Continued Operations**			(4.9)	(16.9)	(53.3)	(43.6)
Note 5	**Darlington Refurbishment**	(0.4)	(7.3)	(21.7)	(11.8)	(11.0)	(7.1)
	Sub-total	**(10.8)**	**(29.8)**	**(99.5)**	**(91.4)**	**(71.6)**	**(50.7)**
	Total OM&A (excluding items above)	**2,017.1**	**1,986.0**	**1,914.2**	**2,024.3**	**1,947.7**	**2,015.3**

Note 1 - As per Ex. F2-T2-S1, page 27, incremental funding for backlog reduction was removed in the 2010 – 2014 business planning process, except for the Pickering A Equipment Reliability Restoration program. The costs shown are for this program.

Note 2 - Consistent with Ex. F2-T3-S1, Table 1.

Note 3 - Costs shown are incremental, consistent with the Outage OM&A exhibits (Ex. F2-T4).

Note 4 - The reference cited (page 19 of the Nuclear Business Plan in Ex. F2-T1-S1, Attachment 1) relates to staff, not costs, and we do not recognize the amounts quoted in part c) of the interrogatory. As disclosed in Ex. F2-T2-S1, page 16, cost of Bruce Power Services are forecast to be $1.8M in 2010, $3M in 2011 and $3.9M in 2012, and Total OM&A (Table 1, line 9 above) already excludes these costs.

Note 5 - Pickering B Continued Operations includes 35 per cent of the cost related to the Fuel Channel Life Management project; Darlington Refurbishment includes the remaining 65 per cent of the project costs.

Board Staff Interrogatory #046

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

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

Interrogatory

On page 22 of OPG's Nuclear Business Plan it discusses "Risks to Business Plan" (F2-T1-S1, Attachment 1) and notes: "*Corrosion of Pickering A Calandria Vault: The corrosion of structural components and cooling systems is being caused by moisture in the vault atmosphere and radiolysis forming nitric acid which attacks the carbon steel components in the reactor vault."* It also notes in OPG's "2009 Annual Information Form" (p.37): *"The uncertainty associated with the electricity volume produced by OPG's CANDU nuclear generating units is primarily driven by the condition of the station components and systems, which are subject to the effects of aging. Significant factors identified to date include steam generation tube corrosion, feeder pipe wall thinning and pressure tube-calandria tube contact. Because no nuclear generating station utilizing CANDU technology has yet completed a full life cycle, there is a risk that additional unforeseen technological or equipment issues could materialize."*

a) Please explain why the Pickering A Calandria Vault issue is showing up now, a relatively short period after the expenditure of the significant refurbishment costs on Units 4 and 1 just a few years ago? Was this issue overlooked at the time or is there another reason why there is an increase in the corrosion of components and equipment in the calandria vault?

b) Please also elaborate in relation to the issues identified, steam generation tube corrosion, feeder pipe wall thinning and pressure tube–calandria tube contact, and the degree and significance of the impact of each of the issues on Pickering A, Pickering B and Darlington.

Response

a) The interrogatory incorrectly refers to "refurbishment costs on Units 4 and 1". The Unit 1 and Unit 4 return to service project was not a refurbishment.

The issue of the corrosive nature of the moist atmosphere in the Pickering A Generating Station calandria vault has been known since the 1980s. It is considered as part of OPG's ongoing life cycle management plan. A large inspection and repair effort was conducted in the mid-1990s to address the issues. The degree to which the corrosion had slowed could not be determined precisely. During return to service of the Pickering A

Generating Station units, an assessment was carried out which showed the components in the calandria vault were fit for service but which recommended follow-up inspections. Tooling was developed to carry out such inspections and the first inspection campaign was completed in the spring 2010 outage at Unit 1. The results are currently under review. In addition, additional drier equipment has been installed to further reduce the corrosiveness of the calandria vault atmosphere. There have been no significant leaks in the calandria vault since restart of the units.

Aging of major components (i.e., steam generators, feeders, pressure tubes) is monitored closely through inspection programs during planned outages.

b) Steam generator aging is more significant at Pickering A and B Generating Stations, and much less significant at Darlington Generating Station. Feeder wall thinning is more significant at Pickering A Generating Station, less significant at Darlington Generating Station, and much less significant at Pickering B Generating Station. The potential for pressure tube to calandria tube contact is more significant at Pickering B Generating Station, less significant at Darlington Generating Station, much less significant at Pickering A Generating Station.

Board Staff Interrogatory #047

Ref: Ex. F2-T3-S3

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

Interrogatory

Please aggregate the contingency amounts (General and Specific) for all of the OM&A Business Case Summaries, for the 2008-2009 period, and identify how much of those contingency amounts were utilized by OPG.

Response

The following table provides the aggregate General and Specific contingency amounts planned for 2008 and 2009 in the OM&A Business Case Summaries ("BCS"), as well as the aggregate contingency amounts approved via the nuclear project management process outlined in Ex. D2-T1-S1 page 10, lines 4 - 12.

Line No.	OM&A Contingency ($M)	2008	2009
	Contingency Planned (BCS)		
1	General	15.9	20.5
2	Specific	1.2	2.2
3	Total	17.1	22.7
4	Contingency Approved (AISC)	6.0	12.7

The approval of contingency requests by the Asset Investment Screening Committee ("AISC") does not identify whether the approval is General or Specific contingency.

As explained in Ex. D2-T1-S1, page 10, lines 4-12, project contingencies are included in the total project costs in the approved BCSs ("Contingency Planned" in the table above), but there are no project contingencies in the project portfolio budget. When project managers receive approval for contingency funding from the AISC ("Contingency Approved" in the table above), the AISC allocates budget from other projects that have been delayed or are being completed under budget.

Board Staff Interrogatory #048

Ref: Ex. F2-T3-S3, Attachment 1, Tab 12

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

Interrogatory

This BCS relates to Fire Safety Assessment (FSA) Upgrade (Project No. 26003). The BCS does not incorporate the FSA requirements of the Pickering A Safe Storage Project and states that the latter will be dealt with separately.

a) In view of the integrated nature of the original configuration and layout of the four-unit Pickering A station, why are the FSA requirements of the Safe Storage Project dealt with totally separate from the Pickering A FSA covering units 1 and 4?

b) What are the associated FSA expenditures for the Safe Storage Project?

Response

a) The FSA requirements for Pickering A Generating Station Units 2 and 3 are in fact being dealt with in a consolidated manner with Units 1 and 4.

   The statement in the Business Case Summary ("BCS") that Pickering A Generating Station Safe Storage project would be "dealt with separately" was in reference to the source of funding (i.e., funding as a decommissioning cost, as opposed to a nuclear project OM&A expense). The Pickering A Generating Station FSA update (to 1995 Fire Code) and upgrade (to 2007 Fire Code) are being managed on an integrated basis for Units 1 - 4.

b) The FSA update expenditures associated with the Pickering A Generating Station Units 2 and 3 are approximately $300k, while the Units 2 and 3 FSA upgrade expenditures are approximately $600k.

Board Staff Interrogatory #049

Ref: Ex. F2-T3-S3, Attachment 1, Tab 13

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

Interrogatory

This BCS relates to Darlington Environmental Qualification Discovery Work and Scope Reduction (Project No. 38458). This project is to meet regulatory requirements with respect to the Environmental Qualification (EQ) of essential (safety related) equipment, components, barriers and structures in order to ensure their operability and functionalities under adverse environments resulting from certain design basis accidents, e.g., a major steam line rupture.

Please clarify if the project costs include required modifications or upgrades to affected equipment, barriers and structures for EQ compliance.

Response

OPG confirms that the project costs include required modifications and upgrades to equipment, barriers and structures necessary for EQ Compliance.

Board Staff Interrogatory #050

Ref: Ex. F2-T3-S3, Attachment 1, Tab 14

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

Interrogatory

This BCS relates to Probabilistic Risk Assessment Upgrade (Project No. 62440). This project is for the upgrade of the Probabilistic Safety Assessments or PSA (sometimes also referred to as Probabilistic Risk Analysis or PRA) for Pickering B and Darlington by December 31, 2010, in compliance with an operating licence requirement for these stations. The PSAs must be compliant with the requirements of the Canadian Nuclear Safety Commission Regulatory Standard S-294, "Probabilistic Safety Assessment (PSA) for Nuclear power Plants".

Based on the limited data in Attachment "A" of the BCS, it is surmised that the combined costs of the analysis services to be contracted out to upgrade the Pickering A, Pickering B and Darlington PSAs and of the general contingencies amount to $23.4M out of the total project costs of $26.8M. As discussed in the BCS, the upgrade of the Darlington PSA will require the most work with relatively minor updating required for the Pickering B and Pickering A PSAs.

a) Please clarify what the basis is of the magnitude of the combined costs of the analysis services to be contracted out and of the general contingencies.

b) Please also clarify how these costs are allocated with respect to the respective PSAs for Pickering A, Pickering B and Darlington.

Response

The assumption that the cost of external contracted work and project contingencies is $23.4M of the total project cost of $26.8M is correct.

a) As indicated on page 2 of the business case summary ("BCS"), the cost estimate is based on a project execution plan provided by the primary contractor and input from potential secondary contractors who will be performing Probability Safety Assessment ("PSA") upgrades. Costing is based on experience to date with recent risk model upgrades, and projected costs for inclusion of an evaluation of internal events such as fire and external events (such as seismic incidents).

   The general contingency amount was developed primarily based on an assessment of additional costs required to mitigate the first two risks included on page 7 of the BCS, i.e., complexity of analysis is greater than expected, and fire/seismic analysis PSA costs are underestimated since this analysis was not part of the previous PSA. This preliminary estimate was then adjusted to provide contingency to address discovery of technical issues and other potential risks.

b) External costs and contingency are allocated as approximately 50 per cent Darlington, 30 per cent Pickering A, and 20 per cent Pickering B. The decreasing costs reflect primarily the efficiencies expected with each successive station's PSA upgrade.

Board Staff Interrogatory #051

Ref: Ex. F2-T3-S3, Attachment 1, Tab 15

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

Interrogatory

This BCS relates to Pickering B Unit 7 Calandria Tube Replacement (Project No. 40669). This project is to replace one calandria tube (Channel A13) in Pickering B Unit 7 as a result of a leak of the Annulus Gas System (AGS) from this location into the heavy water moderator surrounding the calandria tubes, thereby affecting continued safe operation of the unit.

a) What was the final project cost compared to the BCS release estimated costs of $19.8M?

b) The BCS does not provide any clarification with respect to the root cause of the annulus gas leak. Please explain in detail the root cause of the annulus gas leak and why there was a need to replace the calandria tube.

c) The absence of a developed calandria tube cutting tool prior to the replacement of the calandria tube indicates that this may have been an unanticipated problem. Please identify whether this was an isolated incident or whether it is a potential generic issue affecting all Pickering B units and possibly the two Pickering A units. Please also identify if there are any implications with respect to the planned Pickering B Continued Operations project. If so, please explain.

Response

The interrogatory asserts that the leaking Unit 7 calandria tube affected the continued safe operation of the unit. This assertion is incorrect. The flaw in the calandria tube affected the ability to maintain Unit 7 in a guaranteed shutdown state as a result of chemical interaction between the leaking annulus gas and the gadolinium nitrate which was added to the moderator system to effect the guaranteed shutdown state. The calandria tube was replaced to meet the associated procedural, design and regulatory requirements for returning the unit to service.

a) As indicated in Ex. F2-T3-S3 Table 1, line 19, the final project cost was $17.8M.

b) The cause of the annulus gas leak was a failed calandria tube. The calandria tube failed due to an axial crack caused by high cycle flow-induced fatigue, which originated on the external surface of the calandria tube. Wear was observed on the garter spring, pressure tube and calandria tube surfaces, consistent with the presence of abnormal vibration conditions in the failed channel location. The failed calandria tube was replaced to meet operating, design, and regulatory requirements (as noted above) prior to returning the unit to service.

c) The suggestion that this was an unanticipated problem is correct, in that there have been no failures of this type previously in CANDU reactors worldwide. While other calandria tubes have been replaced for different reasons, the frequency of CANDU calandria tube replacement is low. Given this fact, it was decided that the expenditure to develop and procure calandria tube replacement tools as a contingency for OPG's reactors was not warranted.

OPG does not believe this is a generic issue affecting Pickering B or A units, nor are there any significant implications for the Pickering B Continued Operations initiative.

Board Staff Interrogatory #052

Ref: Ex. F2-T3-S3, Attachment 1, Tab 16
F2-T1-S1, Attachment 1, page 22

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

Interrogatory

This BCS relates to Fuel Channel Life Management (Project No. 62444). This project is to accelerate R&D (Research & Development) work to develop better information and the knowledge base with respect to degradation mechanisms and processes affecting the integrity of pressure tubes or fuel channels.

a) On page 22 of OPG's Nuclear Business Plan "Risks to Business Plan", it notes: "*End of Life Determination*: *The medium risk in the confidence level of attaining the planned effective full power hours (EFPH) for Darlington and Pickering B units is insufficient for effective business planning*." Please clarify what the implications are with respect to the planned life extension of the Pickering B units and the planned refurbishment of the Darlington units in the event of each of the following scenarios:

   i) The project is delayed and the planned results and information are not produced in a timely fashion, i.e., in 2012;

   ii) The results and information are inconclusive or negative, i.e., do not support the higher end-of-life operating limits for Darlington (210,000 EFPH) and for Pickering B (240,000 EFPH).

b) If the confidence level of attaining the planned EFPH for Darlington and Pickering B units is insufficient for effective business planning, why does OPG consider the confidence level to be sufficient for Board approval of significant proposed costs related to Pickering B Continued Operations and the Darlington Refurbishment?

c) On page 9 of the Business Case Summary, it is stated that this project will be jointly funded between OPG and Bruce Power with cost sharing at a ratio of 5.5:3.5 (OPG:BP). Please explain the basis of this cost sharing ratio.

Response

a) Answers to questions a) i) and a) ii) are provided together as the implications of delay and the implications of inconclusive or negative results issues are interrelated:

<u>Implications for Pickering Generating Station:</u>

If the results of the Fuel Channel Life Cycle Management ("FCLM") project were delayed, or were inconclusive or negative, OPG would not achieve high confidence by 2012 of achieving 240,000 Effective Full Power Hours ("EFPH") from each of the units.

i) In the case of a delay, to determine how to proceed, OPG would need to assess a number of factors, including the anticipated duration of the delay, Canadian Nuclear Safety Commission ("CNSC") regulatory requirements in effect at that time, and any preliminary results available that would increase confidence in the predicted end-of-life for the station.

ii) If the results were inconclusive or negative, OPG would need to:

- Undertake the activities required to determine the lives of the units and prepare for potential safe storage.

- Advise the OPA and IESO of the predicted end-of-life for the Pickering Generating Station units.

- Initiate planning for an orderly shut-down of the Pickering Generating Station units.

- Assess the impact on OPG's financial outlook.

<u>Implications for Darlington Generating Station:</u>

i) and ii)
As indicated at Ex. F2-T3-S3, Attachment 1, Tab 16, page 3, paragraph 3, the current "high confidence" life of Darlington Generating Station is 187,000 EFPH. The implications of delay, inconclusive or negative results of the FCLM project on Darlington Generating Station are that OPG would need to prepare for early refurbishment of the Darlington Generating Station units. OPG has recognized this risk and is currently working to be ready to start the refurbishment of the first Darlington Generating Station unit in 2015, if required, which is the earliest that OPG assesses that it would be ready to refurbish the first Darlington Generating Station unit.

If the results are inconclusive or negative, OPG would inform the OPA and the IESO as early as possible about any changes to the refurbishment dates for Darlington Generating Station, particularly if these dates are to be advanced.

b) The interrogatory references the 2010 – 2014 business plan presentation to the OPG Board of Directors, where inclusion of this statement as a "strategic risk" was to stress the critical importance of station end-of-life determination, and approval of the associated funding (such as the FCLM project).

Given the value to the Ontario electricity system of Pickering B Continued Operations as assessed by both OPG and the OPA (see Ex. F2-T2-S3, Attachment 2), the need to embark on this work now (as explained in response to part a) i) and a) ii) and Ex. L-01-072), and the significantly increased flexibility OPG would achieve in planning for the refurbishments of the Darlington Generating Station units if the FCLM project were successful, OPG believes that this is a prudent expenditure which should be approved by the OEB.

c) There are two areas of cost sharing under the FCLM project:

- Pressure tube burst testing: shared equally between OPG, Bruce Power and Atomic Energy of Canada Ltd. ("AECL"); and,

- Other R&D programs: shared equally between OPG and Bruce Power (47 per cent each), with a contribution from AECL (6 per cent).

When OPG project management and oversight costs and OPG contingency are added exclusively to OPG's share of the R&D costs, the approximate shares are: 55 per cent (OPG) 35 per cent (Bruce Power) and 10 per cent (AECL), as indicated in the business case summary.

AMPCO Interrogatory #022

Ref: Ex. F2-T1-S1

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

Interrogatory

a) How much station service power has been or will be paid by the nuclear business each year since 2005 through to the end of the test period? Please include a breakout of GA costs.

b) Please provide an estimate of the impact of the AMPCO High 5 proposal as described in EB-2008-0272 if it were to apply during the test period.

c) Please update Chart 2-1: Comparative Nuclear PUEC Costs from the EB-2007-0905 Decision with Reasons.

Response

a) At the nuclear stations, some electricity consumption is self-supplied (i.e., supplied directly from the generators), and some consumption is supplied from the Independent Electricity System Operator ("IESO") -controlled grid (i.e., grid withdrawals). As outlined in OPG's response to the interrogatory in Ex. L-01-088 part b), the IESO does not meter self-supplied consumption but the IESO does meter grid withdrawals. All station electricity consumption, self-supplied or grid withdrawals, is paid by OPG:

- Self-supplied consumption reduces the station electricity output into the IESO-controlled grid. Because this consumption is not metered by the IESO, it does not attract non-energy load charges and OPG does not explicitly track the value of this consumption.

- Grid withdrawals are metered by the IESO and they attract non-energy load charges.

Table 1 below outlines the value of grid withdrawals by calendar year from 2005 - 2009. The first column shows the value of grid withdrawals. The second column shows the total non-energy load charges while the third column shows the Global Adjustment component included in the total non-energy load charges.

Table 1
Nuclear Grid Withdrawal Values: 2005 – 2009

Year	Value of Withdrawals ($M)	Total Non-Energy Load Charges (Including Global Adjustment)[1] ($M)	Global Adjustment (Included in Total Non-Energy Load Charges) ($M)
2005	55.5	10.8	(6.7)[2]
2006	39.5	10.1	3.2
2007	38.0	9.8	3.3
2008	38.6	10.6	4.9
2009	24.8	36.1	26.8

In Table 2 below, an explicit forecast of the cost of grid withdrawals is not available. The first column shows the total non-energy charge forecast while the second column shows the Global Adjustment component of the total forecast non-energy load charge.

Table 2
Nuclear
Forecast Non-Energy Costs: 2010 – 2012

Year	Total Non-Energy Load Charges (Including Global Adjustment)[3] ($M)	Global Adjustment ($M)
2010	26.3	17.0
2011	30.3	21.0
2012	33.5	24.2

b) OPG has no estimate of the impact on its station service costs of this proposal. OPG notes that this matter is before the OEB in EB-2010-0002 and that Hydro One suggests an implementation date of January 1, 2012 in the event that the OEB decides to adopt this proposal.

c) OPG has updated the chart as indicated. OPG does not accept that the Bruce definition of “All In” costs is comparable to the Production Unit Energy Cost (“PUEC”) definition used by OPG.

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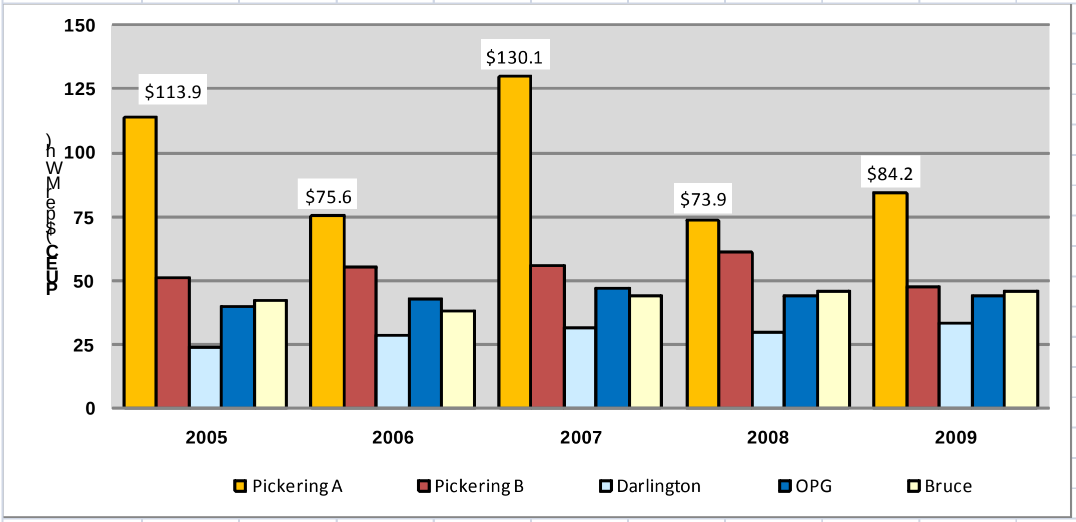
[1] Values from 2005 – 2007 from EB 2007-0905, Ex. F3-T1-S1, Table 12. Values from 2008 – 2009 from Ex. F4-T4-S1, Table 3.
[2] Note that the Global Adjustment in 2005 was a credit and not a cost.
[3] Values from Ex. F4-T4-S1, Table 3.

Update to Chart 2.1 from EB-2007-0906



	Production Unit Energy Cost (PUEC) $/MWh				
	2005	2006	2007	2008	2009
Pickering A	113.9	75.6	130.1	73.9	84.2
Pickering B	51.3	55.5	55.9	61.3	47.3
Darlington	23.9	28.7	31.6	29.7	33.1
OPG	39.7	42.9	47.2	44.0	43.9
Bruce *	42.0	38.0	44.0	46.0	46.0

* Bruce data for 2007, 2008 and 2009 from Bruce Annual Review documents on its website, defined as “All in Costs”. Please note that the 2007 figure was revised by Bruce Power from $42 to $44 and the 2008 number was revised from $45 to $46 as per the 2009 Annual Review document. No disclosure of the change or rationale was provided.

NOTE: The U.S. Median in EB-2007-0905 Chart 2.1 was extracted by OEB staff from a Nuclear Energy Institute report. OPG does not know the context of this report, nor have direct access and does not represent OPG evidence. Therefore, that data has been removed.

PWU Interrogatory #013

Ref: (a): Ex. G2-T1-S1, page 7 of 11, lines 11-13
(b): Ex. G2-T1-S1, page 7, lines 25-31; page 8, lines 1-2
(c): Ex. F2-T1-S1, Attachment 1, page 19
(d): Ex. F5-T1-S1, page 88 of 158

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

Interrogatory

Ref (a) states:

> IMS supports OPG's internal work program needs for fuel channel, steam generator, and balance of plant inspections and specialized maintenance at Pickering A, Pickering B, and Darlington.

Ref (b) states:

> In the spring of 2008, OPG and Bruce Power entered in discussions concerning the future of these service agreements. Both parties wanted to obtain self-sufficiency for the provision of these specialized services. Bruce Power did not want to continue indefinitely with a sole source supply arrangement with OPG. OPG wanted to exit the provision of this non-core business in order to focus on improving outage performance at its stations. OPG's Pickering B Continued Operations initiative will also require extensive inspection and maintenance support. OPG also perceived increased risks and costs related to being able to co-ordinate outage schedules between OPG and Bruce, given the refurbishment of additional units at Bruce.

a) Given that Inspection and Maintenance Services staff serve OPG as well as other parties (e.g. Bruce), and that the need for these services is increasing in OPG as the units age, how does OPG determine that the planned reduction in the highly skilled staff identified in Ref (c) (see below) will leave adequate staffing numbers to conduct the required inspection of OPG's aging units. In particular please reference the staffing needs for pressure tube life management.

Ref (c) outlines the staffing plan that identifies for 2012 a plan-over-plan reduction of 110 staff in inspection and maintenance services, or 150 based upon 2009 levels. It also identifies a plan-over-plan reduction, for 2012, of 46 staff in nuclear programs and training staff.

b) How will the proposed plan-over-plan Inspection and Maintenance staff reductions as well as the expected attrition rate of these staff over the 2010-2014 business plan impact OPG's need for training staff?

c) How are the nuclear training programs impacted by the reduction in training staff? If so, please describe how OPG will address the impacts.

Ref (d) states:

> For the review period, approximately 7% of the Pickering A FLR was attributable to human performance…

d) The FLR attributable to human performance at Pickering A is estimated at 7%. What impact will the plan-over-plan reduction in training staff have on OPG's ability to train new staff and enhance the capabilities of existing staff to reduce the percentage of FLR attributable to human performance?

Response

a) The Inspection and Maintenance Services ("IMS") staff reductions forecast for 2009 – 2012 (identified in Ex. F2-T2-S1, Table 14, line 37) are predominantly due to the termination of IMS's obligation to service Bruce Power, and reflect removal of the staff numbers dedicated to Bruce Power work or providing support to those functions. The remaining staff reductions are part of OPG's overall plan to improved efficiency. IMS will continue to be able to supply the required level of OPG station support.

To ensure that OPG has adequate resources to support OPG stations, the demand for inspection and maintenance work is reviewed each year as part of business planning, using the current station life cycle plans. IMS then prepares detailed schedules of staff requirements, to be met by regular staff with augmentation via contractors or other temporary staff for peak resources required during outage periods. The 2010 – 2014 business planning process has confirmed the adequacy of trained staff and other resources to support the ongoing station inspection and maintenance programs, as well as incremental efforts associated with pressure tube life management such as the Fuel Channel Life Cycle Management project.

b) OPG does not foresee any significant impact of the above-noted factors on the need for training staff. As indicated in the response in Interrogatory L-11-014, part b), inspection and maintenance technicians are typically hired with full technical qualifications, which are then supplemented by in-house training. The in-house training is currently provided by a dedicated training instructor, supplemented by line staff training delivery on a part-time basis, and OPG foresees that this will continue.

c) No negative impact of the nature described is expected, as reductions in Nuclear Programs and Training are forecast to be primarily in the Nuclear Integration and Nuclear Programs functions.

d) No negative impact is expected, as reductions are forecast to be primarily in the Nuclear Integration and Nuclear Programs functions.

PWU Interrogatory #014

Ref: (a): Ex. F2-T3-S3, Attachment 1, Volume 3 of 3, Fuel Channel Life Management 10-62444, Partial Release Business Case Summary N-BCS-31100-10001-R000, PDF pages 145 to 160
(b): Ex. F2-T2-S3, page 7 of 13
(c): Ex. A1-T3-S3, page 8, lines 11-12

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

Interrogatory

a) Are the currently budgeted maintenance activities on other components sufficient to allow full exploitation of any extended life of pressure tubes? Please identify and discuss any major deficiencies and whether they are related to cost cutting measures.

b) What plans are in place to ensure that OPG or its contractors retain or attract skilled staff and train them for the requisite skill sets needed to carry out this specific project and any needed accompanying inspections, pressure tube/spacer replacements and engineering modifications?

c) Does the level of maintenance included in the 2010 - 2014 business plan reflect an expected refurbishment date of 2014 - 2016? How does the level of maintenance included in the 2010 - 2014 business plan assist this project in mitigating the risk of delays in the refurbishment schedules? Please identify and discuss any additional maintenance over and above the level included in the 2010 - 2014 business plan needed to fully exploit any success from this project.

d) Ref (a) PDF page 146 of 160 states:

> As a result, OPG fuel channel experts have only medium confidence (up to 70%) that the pressure tubes in Darlington will achieve its nominal operating life of 210k EFPH. This is due to a lack of scrape data from the Darlington Units to support model predictions, the fact that Darlington Unit 3 scrape samples in 2002 exhibited some very high uptake trends that exceeded the upper bound of the CANDU 6 model, and that Darlington pressure tubes have some of the highest initial impurity hydrogen (Hinitial) values in any CANDU units. Other contributing factors include a scarcity of rolled joint Heq data and lack of a predictive rolled joint model. If the currently defined EOL limits are reached in Darlington earlier than 210k EFPH, then it may be necessary to advance the refurbishment schedule from the current plan of 2016 to as early as 2014. …Aside from issues concerning reaching this limit, it should be recognized that there little high hydrogen material property data

> from ex-service pressure tubes. Hence, there is insufficient data to provide the needed technical basis supporting operation of pressure tubes with Heq above the solubility limit and beyond.

Ref (a) PDF page 146 of 160 states:

> Until recently, Pickering B was not expected to exceed the EOI limits during the pressure tube nominal operating life of 210k EFPH. This expectation was related to the lower operating temperatures in Pickering B. However, the hydrogen and deuterium profiles through the inlet and outlet rolled joint regions of surveillance tube P6 M14 have challenged this belief (report issued December 2008). It appears that P6 M14 has much higher deuterium uptake in the compressive regions of the pressure tube and Heq exceeds the solubility limit at both inlet and outlet rolled joint burnish marks.

The evidence states that there is “a lack of scrape data from the Darlington units to support model predictions”, a “scarcity of rolled joint H_{eq} data” and a “lack of a predictive rolled joint model”. Are any of these deficiencies a result of past deferral or cancellations of recommended pressure tube work? If so, how were short-term production increased and costs reduced as a result of any deferrals? Please comment on whether these deferrals were advantageous given current circumstances described in the Partial Release Business Case Summary (“BCS”) N-BCS-31100-10001-R000.

e) On page 8 of the Partial Release BCS Alternative 5, in speaking to the possibility of accelerating this program the BCS notes that while it would be “very beneficial” … “the current limitation in the work is resources – specifically technical experts, technicians and facilities”. Could this shortfall in resources apply to work, such as inspections etc. that must be accomplished in parallel with this research to fully exploit any success in redefining fitness for service criteria? Are current or past cost cutbacks a contributing factor to this? Please elaborate.

f) Please explain the following entries in the risk table (pages 11 and 12) in the Partial Release BCS:

   i) “Funding not available in time to complete work” and “Other EOL work not funded - negating large benefit of this work”. Would this risk be imposed as a result of additional cost cutting?

   ii) “FC LCM work not completed during outages to obtain the necessary data”. Assuming that FC LCM refers to Fuel Channel Life Cycle Management. Has recommended or scheduled fuel channel life management work been deferred in the past? If there were deferrals, what plans are there to obtain sufficient inspection data to fully exploit whatever limits are set for both Darlington and Pickering i.e. in catching up on the deferred work and any additional work? What is the impact of these plans on costs, staffing and training needs and outage extensions going forward?

g) Ref (b) states the NPV of continued operation at Pickering B is $1.1 Billion.

Ref (c) states:

> The Darlington Refurbishment project will require significant capital expenditures, estimated at between $6B and $10B (2009 dollars) over the life of the project.

Why is this Life Management Project being undertaken so late in the life cycle that its timing might dictate the timing of the $6 billion to $10 billion Darlington refurbishment project and determine the success of the $1.1 B NPV continued operation project at Pickering?

Response

a) Yes, the currently budgeted maintenance activities for Darlington Generating Station and Pickering B Generating Station are sufficient to allow full exploitation of any extended life of pressure tubes, and no major deficiencies were identified as part of the 2010 – 2014 business planning process.

Pickering B Continued Operations was assumed as part of the 2010 – 2014 business plan. Funding was included to complete inspection and maintenance programs on major components as defined by the life cycle management program, implement the Fuel Channel Life Management ("FCLM") Project, and conduct maintenance activities on the balance of plant equipment consistent with continued operations.

For Darlington Generating Station, please see additional information provided in c).

b) The Inspection & Maintenance Service ("IMS") Division executes or contracts all of the pressure tube inspection work, including that required for the Fuel Channel Life Cycle Management Project. The IMS Workforce Deployment Department has systems in place to track the training requirements and qualification of staff, and coordinate training for both OPG staff and contractors as required. Attracting and retaining skilled staff is generally not an issue in IMS. Turnover in IMS is generally low, and Durham College offers a diploma-level Inspection and Maintenance Technician Program which routinely graduates approximately 20 technicians per year. In anticipation of a larger workload at Pickering B Generating Station, IMS is providing additional training to existing technicians to perform the work.

For contractors, longer term agreements with key contractors have been established and metrics are used to assess their in-house training and ability to retain trained staff.

Engineering and project management capability within nuclear is monitored, and an integrated workforce management program is in place to ensure adequacy of resources, including those involved with fuel channel management issues.

c) The level of maintenance included in the 2010 – 2014 business plan is largely independent of the planned 2016 refurbishment date, in that OPG intends to continue to maintain and improve Darlington Generating Station's plant condition such that the refurbished units can continue to strive for top operational performance.

The 2010 – 2014 business plan provides adequate funding to support success of the refurbishment program and subsequent operations.

d) The data deficiencies cited in the interrogatory are not the result of past deferral or cancellation of recommended pressure tube work.

There are two main reasons for paucity of scrape data as noted below:

- The tooling to carry out scrape sampling in the rolled joint region has only been developed in the last few years.

- For "body of tube" scrape at Darlington Generating Station, the volume of data available is limited because an alternate technology was used during the 2003 – 2008 period to collect hydrogen data. It was subsequently found that the data from this tool was not sufficiently accurate to be useable and the use of the tool was suspended in 2008. Scrape sampling was resumed in 2009.

e) The limited resources referenced in the business case summary ("BCS") are specifically the technical staff and facilities at contractor and vendor organizations required to carry out the experimental work associated with the FCLM project. For the duration of the project, the volume of such work is planned to be approximately double the level in the ongoing CANDU owner's group ("COG") Fuel Channel R&D program. The discussion in Alternative 5 was intended to note that it would not be possible to ramp the level of work up any higher, as the highly specialized people and facilities would not exist to support the higher level of effort.

Fuel channel inspection capability has not been limited by cost cutbacks.

f) i) Given the importance of the FCLM Project to OPG, there are no foreseeable conditions under which the referenced funding risks would be imposed as a result of additional cost cutting.

ii) The inspection work prescribed in the FCLM Project has mostly been completed during the outages in which it was planned. The main reason for deferrals of some parts of the work is occasional failures of the inspection equipment during the inspection campaigns that result in an inability to complete the full campaign during the allocated outage window. Deferred scope items are assessed for criticality to success of the FCLM Project, and rescheduled as appropriate into a subsequent outage.

g) Work to address the long-term integrity of pressure tubes has been ongoing for many years through the COG Fuel Channel R&D program. The FCLM Project was started in 2009 to supplement and accelerate the work of the COG R&D program, allowing OPG to more aggressively address the uncertainties in the plan for Pickering B Continued Operations and Darlington Refurbishment.

The principal issues that led to the creation of the FCLM Project have only come to light fairly recently, relatively late in the life cycle of the units. For example, the issue of anomalous hydrogen pick-up in Pickering B Generating Station's rolled joints was highlighted by the results of the inspection of a surveillance tube removed in 2007. The concern over garter spring degradation at Pickering B Generating Station developed following the replacement of the fuel channel A13 in 2008, and the potential embrittlement of the Darlington Generating Station garter springs was noted during the removal of a surveillance tube in 2005.

PWU Interrogatory #015

Ref: (a): Ex. D2-T1-S1, pages 3 and 4 state:

> Cost-focused reductions in the OM&A portfolio have resulted in a significant deferral of planned work beyond the test period. The OM&A portfolio has been reduced from a budget of $118M for 2008 and 2009 as approved in EB-2007-0905, to a comparative budget of $111.7M in 2010, $108.3M in 2011 and $111.2M in 2012. Managing to the OM&A portfolio levels listed in Chart 1 will therefore require continued careful assessment and prioritization of work across OPG Nuclear.

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

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

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

Interrogatory

(a) Please provide the information in Chart 1 in constant dollars.

(b) Does Chart 1 above include or exclude the SAVH of approximately $12 million/year?

(c) Does "cost-focused reductions" imply that those cost reductions were made in isolation from their impact on net value? Please provide a list of the planned work deferred together with the impact of the deferrals on net present value over the station life cycles, taking into account both costs and benefits that would have accrued to the plants had the work been done on the original schedule. If this is not available please indicate how net value entered into the decisions to defer, or eliminate, planned work.

(d) Please discuss any increase in risks resulting from deferrals of work.

(e) Please comment on the impact of this deferral on future costs, staffing needs and performance metrics.

(f) Please comment on the impact of aging on the need for additional work. Directionally would you expect an increasing workload? Please provide an explanation in your response. Is this consistent with the decisions to defer work into the future?

Response

a) The following chart represents the total Nuclear Portfolio Costs in constant 2007 dollars.

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

2007$	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Project Portfolio – Capital ($M)	186.5	157.0	152.3	160.3	155.9	151.7
Project Portfolio – OM&A ($M)	102.1	116.4	115.4	104.1	98.1	98.1
Total Project Portfolio ($M)	288.6	273.4	267.7	264.4	254.0	249.8

b) Chart 1 includes Sickness, Accident, Vacation and Holiday ("SAVH") of approximately $12M per year in years 2010 onwards. As indicated in Ex. D2-T1-S1, page 4, lines 9-14, the OM&A budget for 2010 onwards was increased to offset forecast SAVH costs; the capital budget was not increased to offset such costs.

c) No, 'cost-focused reductions' does not imply that those cost reductions were made in isolation of their impact on net value. As outlined in Ex. D2-T1-S1, Section 3.1, it is the role of the Asset Investment Screening Committee ("AISC") to prioritize project work to provide highest value. This is done on the basis of the project Part A screening forms (characterizing the issue, operational and financial impact, and relative ranking of potential impact) supplemented by the broad senior management experience of the AISC members. Lower priority work is deferred until it can be accommodated within planned portfolio funding. The work that will potentially be deferred beyond the test period due to project portfolio funding levels is the "Listed Work to be Released" (Ex. D2-T1-S2 Table 5a, 5b and Ex. F2-T3-S3 Table 4a and 4b). As indicated above, any such judgments will be made on the basis of AISC assessment of project value. Critical work will not be deferred.

d) As part of the AISC process, project deferral risks are assessed and compensatory measures put in place to manage them within acceptable levels. For example, a reasonable compensatory measure pending implementation of a project to replace a component might be to increase the frequency and scope of maintenance activities; such a measure would incur a short-term cost in labour and parts, and this increased cost would be assessed against the value of deferral or cancellation of the project.

e) Potential impacts of project deferrals would be assessed and considered as part of the AISC project ranking decision process outlined above.

f) The aging of the stations will have an impact on the composition of the project workload but not the overall amount, which is determined by the approved project portfolio level. The OM&A portfolio is forecast to have more small scale projects and minor modifications than large projects. The number of larger OM&A projects is expected to decline with the completion of major initiatives such as the Darlington environmental qualification projects.

As Pickering A and B Generating Stations approach their end of life, the focus at those stations will be on smaller OM&A projects addressing replacement of obsolescent components rather than larger capital upgrades or replacements. This increase in OM&A spending at Pickering will be offset by reductions in capital.

The focus at Darlington Generating Station will be on capital upgrades and replacements necessary to extend the life of the plant. Increasing capital spending will be offset by reductions in OM&A work at Darlington.

Decisions on the Pickering B and Darlington Refurbishments have changed the types of projects needed at those stations. Significant capital upgrades may not be economically viable at Pickering A and B Generating Stations, whereas, obsolescence and performance issues at Darlington need to be addressed by more enduring solutions that are consistent with extended station life.

PWU Interrogatory #016

Ref: (a): Ex. F2-T3-S3, Volume 3 of 3, PDF Pages 134-144 of 160, Calandria Tube Replacement Execution 13-40669 OM&A, Full Release Business Case Summary NK30-BCS-31230-00002-R000

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

Interrogatory

Ref (a) is a business case for the replacement of leaking calandria tube that resulted in the forced outage for April 2008 through to November 2008.

a) Did the unavailability of the calandria cutting tool in April 2008 contribute to the length of the April 2008 through November 2008 forced outage?

b) If your response to (a) is yes, please indicate the degree of extension of the forced outage that was attributable to the unavailability of a calandria tube cutting tool.

c) Please confirm that the original scheduled cutting tool readiness of September 2009 was a result of repair work related to the leak identified in 2005, planned for a date later than September 2009.

Response

a) The unavailability of the calandria tube cutting tool was not a significant contributor to the forced outage extension of April 2008 to November 2008. The activity that took the longest to complete was the removal of the residual gadolinium from the calandria vessel. Developing, qualifying and applying the process to remove this gadolinium was a determining factor in the ultimate length of the forced outage.

b) N/A

c) Replacement of the calandria tube was originally scheduled for the 2010 planned outage of Unit 7 following the tool readiness target of September 2009. As discussed in EB-2007-0905 Ex. N1-T1-S1, engineering reviews, including a third party assessment, had indicated that the unit could safely operate to time of the planned outage when the calandria tube was to be replaced.

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 #021

Ref: Ex. F2-T2-S1, page 22

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

Interrogatory

a) Please provide the documents which incorporate the CNSC regulatory obligation to fund nuclear research.

b) The evidence states that OPG will invest approximately $16 million during the test year on nuclear R&D. Please explain how this amount is determined.

Response

a) The requested documents are provided in Attachment 1, which includes a February 26, 2002 Canadian Nuclear Safety Commission ("CNSC") letter requesting assurances with respect to continued research and development ("R&D") funding (Attachment 1, page 2, paragraph 5); and, an April 17, 2002 OPG response which includes OPG's assurance that R&D funding commitments will continue (Attachment 1, page 5). Attachments to the letters have not been provided because they are lengthy and not specific to the regulatory obligation to fund R&D.

b) As presented in Ex. F2-T2-S1, OPG invests in a number of R&D activities which are jointly funded with other industry partners, with annual review and adjustment as required. Ex. F2-T2-S1, Attachment 1, Chart 1 provides the relative components of the programs that make up the amount of $16M, and indicates minor program changes that have influenced total R&D funding over the 2007 – 2012 period. OPG's share of the cost of each of these activities is negotiated with OPG's funding partners based on the following principles:

R&D Program Item	Funding Partners	Sharing Principle
COG R&D Program	OPG, Bruce Power, Hydro Quebec, New Brunswick Power, SNN Romania, Atomic Energy of Canada Limited (“AECL”).	Number of operating units. (AECL provides supplementary funding, as per COG agreements.)
COG Joint Programs	Specific to each program.	Number of operating units. (Flexibility to adjust if appropriate.)
EPRI Nuclear R&D Program	OPG, Bruce Power, Hydro Quebec, New Brunswick Power, SNN Romania.	Number of operating units. (Includes timing of new/laid-up units coming online.)
UNENE Nuclear Engineering R&D Program	OPG, AECL, Bruce Power are the primary partners.	Based on specific agreement to 2012. (OPG pays approximately 60 per cent; Bruce Power/AECL each pay approx. 20 per cent.)

Canadian Nuclear Safety Commission
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Directorate of Power Reactor Regulation

Your file Votre référence

Our file Notre référence

- H17

February 26, 2002

26-0-0-0-0

N-CORR-00531-01981

Executive Vice President
and Chief Nuclear Officer

MAR 06 2002
Refer To: org. to C. Jobe
☐ For your information ☐ Let's discuss
☐ Take appropriate action ☐ Draft reply for my signature
☐ Return with comments
Additional Instructions:

Mr. G. Preston
Executive Vice-President and
Chief Nuclear Officer
Ontario Power Generation
700 University Avenue, H19-A20
Toronto, Ontario M5G 1X6

Subject: Research and Development

Dear Mr. Preston:

We acknowledge receipt of your submissions regarding the 2000/2001 Research Program [1], and the COG strategic plan [2].

In recent years, with the decline in research and development funding, Canadian Nuclear Safety Commission (CNSC) staff has been monitoring the program funding more closely. Following the capability review [3], the funding was subsequently stabilised. However, we note that there were many vulnerable areas identified in the report in the near and medium terms. After reviewing this year's COG summary report we have concluded that it does not permit the degree of regulatory monitoring that we now consider to be necessary. The purpose of this letter is to outline more detailed reporting requirements for R&D, and to obtain other related information that will permit closer regulatory monitoring.

R-99 Requirement for Research and Development Reporting

In the past, CNSC staff accepted the COG safety and licensing annual summary report as the sole means by which power reactor licensees met their R-99 obligations with regard to annual reporting of their R&D programs. You are advised that the COG summary report will no longer be considered sufficient for R-99 reporting purposes. In future, we require reporting on all technical areas that have implications for safety in the near and medium terms.

We request that you provide a list of research areas for regulatory reporting under R-99. Attachment 1 identifies the minimum information that is required; you may decide to report for other technical areas to demonstrate your continued commitment to safety-related research.

In addition, we request that you inform the CNSC staff of upcoming significant changes in research direction prior to these being implemented. Examples of such changes include significant changes in funding for specific research areas, and closure of experimental facilities. To assist in our assessment, we request that you provide a list of all significant facilities related to CANDU R&D, their projected lifetime and associated current and planned R&D programs.

Assurance of Continued Funding and Maintenance of Expertise

Following the sequence of funding reductions in the period of 1996 to 2000, the industry undertook a capability review [3] to assess the adequacy of research programs and infrastructure necessary to support safe operation of Canadian CANDU reactors. There were two important outcomes of this report: a stabilisation of research funding, and an improved understanding of vulnerable areas.

Given that the review identified a significant number of areas where facilities or expertises were vulnerable in the near term (0-3 years) and in the medium term (3-10 years), it is important that this situation is monitored by the industry and by CNSC staff. Therefore, you are requested to update the capability review [3] on a two-yearly basis starting in 2002. You are requested to confirm that a revised version will be completed by June 2002.

We also note that funding continues to be on an annual basis, whereas business plans are on a multi-year basis (frequently 3 to 5 years). While we accept that the research funding may get adjusted annually, we wish to gain an assurance of the planned expenditures on research over the complete business planning cycle.

Finally, with regard to funding for the fiscal year 2002/2003, we note that there are a large number of outstanding safety and licensing issues, and it is our expectation that the funding for COG safety and licensing research will be similar to or higher than the previous year.

COG Strategy for Future R&D

The strategy, as outlined in reference 2, appears to be a sound basis for planning near and midterm COG activities. We note that it is important to ensure that the strategic objectives will be implemented through timely programs, and this will require significant resources.

The CNSC staff has reviewed the strategy, and comments are included as attachment 2. We request that in preparing revisions to the strategy document, COG takes into account these comments.

The strategy document identifies a number of specific objectives and initiatives. We request that you provide a report of progress to the end of 2001 for each of these.

A summary of the requested information and the due dates is provided in Table 1 attached.

A similar letter has been sent to Bruce Power, Hydro-Québec and New Brunswick Power.

Yours sincerely,

j.w. blyth

J.W. Blyth
Director General

c.c.: V. Langman (COG)
B. Ecroyd (CNSC)
L. Macdonald (CNSC)
J. Tong (CNSC)
A. Ling (CNSC)
J. Douglas (CNSC)

References

1. "Safety and Licensing - R&D Program, Annual Report - FY 2000/2001", Volumes I and II, COG 00-315 V1 & V2.
2. "A Strategy for Future COG R&D", COG 00-305, March 2001.
3. "CANDU Research and Development Capability Review", COG-00-059, March 2000.

ONTARIO POWER GENERATION

RECORD COPY

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April 17, 2002

File: N-00531 P
CD# N-CORR-00531-02003

MR. J. BLYTH
Director General

Canadian Nuclear Safety Commission
280 Slater Street
Ottawa, Ontario
K1P 5S9

Dear Mr. Blyth:

Research and Development

Reference:

1. CNSC letter, J. W. Blyth to G. Preston, "Research and Development," February 26, 2002, CD# N-CORR-00531-01981.
2. "A Strategy for Future COG R&D," March 2001, COG-00-305.
3. "CANDU Research and Development Capability Review," March 2000, COG-00-59.

This letter provides an initial response to the CNSC request for information on research and development (R&D) programs (Reference 1). In preparing our response, we have consulted with our colleagues from other Canadian utilities and the COG Office. In addition to industry programs, information on specific OPG initiatives will be presented in a separate submission.

Given the expanded reporting requirements requested in Reference 1, the Canadian utilities would like to arrange a meeting with your staff in May, 2002, to clarify CNSC's expectations. Mr. M. A. Tidbury of COG will be contacting your office to schedule the requested meeting. In advance of this meeting, we have attached a full listing of the COG R&D Programs for 2002/2003 and other available information in response to the requests made in Attachment 1 of Reference 1. Other information requested would be provided by June 30, 2002 (see Table 1).

Ontario Power Generation will be working with the other COG utility members to provide the CNSC with the information required for a complete response. This will require significant effort and is the basis for the schedule provided in Table 1.

Filed: 2010-08-12
EB-2010-0008
L-12-021
Attachment 1

In your letter you express concern regarding commitment to continued funding of R&D programs. The funding of OPG's R&D activities is determined in terms of issues, the cost sharing agreement between COG members and the R&D endeavours supported by OPG on a unilateral basis. In 2002/2003, COG members will invest approximately $36 million in R&D, including participation in EPRI. OPG has maintained the necessary level of funding for the COG safety and licensing program over a number of years without adverse effect. In fact, a number of programs have seen their funding increased above the initial estimates, when needed. There is currently no intent to change this level of funding. This, in our view, provides the assurance that R&D funding commitments will continue. OPG does include R&D in its normal business planning process. Our current plans, which are elaborated in a separate submission, show a projection of a constant level of funding over the period 2002 - 2006.

We will work with our utility colleagues in arranging a meeting with your staff to further discuss this issue. For further information, please contact Mr. John Baron, Manager, Technology and Research, at (416) 592-6361.

Sincerely,

P. Charlebois
Nuclear Chief Operating Officer &
Chief Nuclear Engineer

Attach.

SEC Interrogatory #022

Ref: Ex. F2-T2-S1, Table 2 and Table 14

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

Interrogatory

Between 2009 and 2012 the evidence states that FTEs in the Nuclear Operations will be reduced by 673 FTEs. During that same period costs of regular staff costs increase by $901.3M to $941.8M.

a) Please explain and provide the quantitative analysis which shows how this 9% drop in FTEs results in a 4.5% increase in labour costs.

b) Please provide the analysis for each year 2009 through 2012 which shows the net reduction in FTEs, the annual savings and the annual costs incurred in making the FTE reduction.

Response

a) The premise in the question is incorrect because the data in Ex. F2-T2-S1, Table 14 (Total Work Program Regular Headcount or FTEs) and Ex. F2-T2-S1, Table 2 (Base OM&A - Nuclear) are not directly comparable due to the following reasons.

   Table 14:
   - Includes Nuclear Operations staff associated with all cost categories, except for those staff whose work is funded by Nuclear Waste Provisions.
   - Excludes the Nuclear Security function.
   - Excludes non-regular staff.

   Table 2 – Labour Regular:
   - Includes OM&A Base cost category only.
   - Includes the Nuclear Security function.
   - Includes non-regular staff costs.
   - Includes an extra week of labour cost in 2012 due to the OPG fiscal calendar being 53 weeks in 2012 (as explained in Ex. F2-T2-S1, page 16, lines 8, 9).

b) Presented below is a table of overall Full-Time Equivalent ("FTE") reductions from Ex. F2-T2-S1, Table 14. Recognizing that these FTEs are contributing to several work programs and not just the Base OM&A resources presented in Ex. F2-T2-S1, Table 2, OPG has calculated the approximate savings that OPG has been able to realize through staff reductions. This calculation uses an average labour cost per FTE for each year of the analysis.

Year over Year	FTE Reduction	Average cost / FTE ($ - k)	FTE Savings ($ - k)
2009- 2010	177	136	24,072
2010 - 2011	347	141	48,927
2011 - 2012	149	144	21,456
Note: 2009 number is Headcount, not FTE			

As the strategy is to use attrition to achieve these forecast FTE reductions, there are no incremental costs associated with these staff reductions.

This analysis represents the savings from a lower volume of labour resources. In order to assess total labour costs, the impact of escalation to account for labour agreements and inflation (see Ex. L-1-075) as well as payroll burden must also be considered (see Ex. L-1-085).

SEC Interrogatory #023

Ref: Ex. F2-T2-S1, page 30, Table 1

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

Interrogatory

a) Please show how the Workforce Development Program costs are allocated to Base OM&A (i.e. show the allocations of these costs in Table A, D2-T1-S1, pg.1).

b) There is a 22% increase in the Programs & Training costs of the Nuclear support divisions. Please provide a table showing the major cost components of this function for the period 2007 to 2012.

Response

a) The table referenced in the question is a nuclear capital projects table and does not relate to the Workforce Development Plan. Since the Workforce Development Plan is Base OM&A, OPG has provided the allocations in the format of Ex. F2-T2-S1, Attachment 3, Chart 1. The totals reconcile to Ex. F2-T2-S1, Attachment 3, Chart 1.

Workforce Development Program Cost Allocation to Divisions						
Costs ($M)	2007 Actual	2008 Actual	2009 Actual	2010 Plan	2011 Plan	2012 Plan
Pickering A	2.2	6.2	5.3	3.7	5.2	5.6
Pickering B	5.0	6.8	6.7	8.2	7.5	7.2
Darlington	6.9	8.3	9.6	7.3	5.3	6.7
Programs & Training	1.7	1.0	0.5	0.4	(0.1)	(0.4)
Total	15.9	22.4	22.1	19.6	17.8	19.1

b) The requested information is provided in the table below. As shown below and in Ex. F2-T2-S1, Table 1, line 10, there are significant increases in Programs and Training actual costs in both 2008 and 2009. The explanation for these increases is provided at Ex. F2-T2-S2, page 5, lines 19-24, and page 7, lines 10-14. The primary drivers of the $35M (22 per cent) increase are a 2009 organization transfer of a function in from the Performance Improvement and Oversight ("PINO") Division ($21M, which is offset by a reduction in PINO); and security-related costs ($9M in 2009 and $4.8M in 2008).

Line No.	Programs & Training Department	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	Records & Admin	33.5	32.3	26.0	25.3	23.8	25.4
2	Nuclear Programs and Training	78.7	84.6	110.8	104.1	108.0	110.1
3	Security	47.8	52.6	61.6	62.2	61.5	59.5
4	**Programs & Training**	**160.1**	**169.5**	**198.4**	**191.5**	**193.3**	**195.1**

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.**

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L-12-024
Attachment 1

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

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L-12-024
Attachment 1

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

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

Effectiveness Measures:

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			

Initiative Action Plan

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

Initiative Action Plan

Initiative Number: TR-06

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.