ONTARIO POWER GENERATION

BUSINESS CASE SUMMARY

Inspection Qualification Project 10 - 66105 OM&A 10 - 62552 Capital

Partial Release Business Case Summary N-BCS-04160-10000-R000

1/ RECOMMENDATION:

We recommend a partial release of $4.02M (incl $[redacted]M contingency) for the Inspection Qualification Project.

The Business Objective is to demonstrate compliance with the CSA N285.4 by providing a systematic and well-documented approach to NDE qualification, based on nuclear industry good practices. Compliance with the CSA N285.4 standard is a requirement of the Power Reactor Operating Licences for the Darlington & Pickering Stations. Clause 3.6e has been part of the standard since 1994 and requires the Owner to "demonstrate the adequacy of the procedures and the proficiency of the assigned personnel using the assigned equipment to detect and size flaws in representative samples". To date, within OPG-N, there has not been a systematic and well-documented approach to NDE qualification. (see Background Section)

The CNSC has communicated its increasing interest in this subject, questioning OPG-N to demonstrate compliance with CSA N285.4, Clause 3.6e for feeder cracking, steam generator tube inspection, and fuel channel inspection on an ad-hoc basis, and by commissioning its own studies on approaches for CANDU Reactor NDE Qualification.

We are recommending a staged approach with development of specifications, governance, PEPs, and some initial qualification work, to provide a better understanding of work scope and estimates of timing, costs and deliverables prior to requesting for future release funding for the 2010-2012 timeframe.

A developmental release of $1.5M (Phase-1) is being used to establish CIQB and its governance and to complete Inspection Specifications (ISs) for Fuel Channel (FC), Steam Generators (SGs) and Piping. Project Execution Plans (PEPs) were also developed for the issuance of Inspection Qualification (IQ) dossiers by IM&CS.

Subsequently, we are recommending 2 Partial funding releases to finalize the scope and move work forward, followed by a final release to complete the project. The work to be undertaken in each phase is detailed in the Proposal Section. Inspection Specifications and qualification work for Feeders were included in the COG Feeder Integrity Joint Project. Funding for continuing oversight for Feeder Inspection Qualification is included in this project.

$000's (incl contingency)	Funding	LTD 2006	2007	2008	2009	2010	2011	Later	Total
Currently Released	Developmental		332	1,068					1,400
Requested Now	Partial			132	3,890				4,022
Future Funding Req'd	Partial				132	3,800	1,000		4,932
Future Funding Req'd	Full						2,631	1,747	4,378
Total Project Costs		-	332	1,200	4,022	3,800	3,631	1,747	14,732
Ongoing Costs									-
Grand Total		-	332	1,200	4,022	3,800	3,631	1,747	14,732
Investment Type Sustaining		Class Cap & OM&A		NPV (9,196)		IRR N/A		Discounted Payback N/A	

Submitted By:

Paul Spekkens Dec 4, 2008

P. Spekkens Date:
VP, Science & Technology Development

Finance Approval:

R. Leavitt Dec 22, 2008

R. Leavitt Date:
VP, Nuclear Finance

Line Approval (Per OAR Element 1.1 Project in Budget):

T. Mitchell 23 Dec 08

T. Mitchell Date:
Chief Nuclear Officer

2/ BACKGROUND & ISSUES

The qualification of Non-Destructive Examination (NDE) inspection processes is a requirement under the Canadian Standards Association (CSA) standard for periodic inspection, CAN/CSA-N285.4. Compliance with this standard is a requirement of the Power Reactor Operating Licences for the Darlington and Pickering Nuclear stations. Clause 3.6e, which has been part of the standard since 1994, requires that the Owner "demonstrate the adequacy of the procedures and the proficiency of the assigned personnel using the assigned equipment to detect and size flaws in representative samples." Note: NDE "performance demonstration" and "qualification" are used interchangeably in this BCS.

To date within OPG-Nuclear, NDE procedures and personnel have been qualified in accordance with existing governance, which, in the absence of more detailed engineering requirements and a standardized qualification process, permits a fair degree of interpretation and latitude in what constitutes an acceptable qualification. As a result, there has not been a systematic and well-documented approach to NDE qualification.

Inspection Qualification is practised in the Nuclear Utility business in other jurisdictions. Examples include the Performance Demonstration Initiative (PDI) in the U.S. and the European Network for Inspection Qualification (ENIQ) in Europe. A pilot study completed by OPG-N in May 2001 [1] involved a review of the optimal approach to demonstrate compliance with the CSA N285.4-94 Standard. It proposed a process based on Recommended Practices followed by ENIQ to complete inspection qualification. A recent CNSC-sponsored project on Inspection Qualification processes [2] also endorsed an ENIQ-based methodology as the most appropriate inspection qualification methodology for CANDU application.

The key elements of the ENIQ process include development of:

- Inspection Specifications that define what must be achieved by the inspection procedure, including addressing component-specific degradation mechanism(s), areas affected, and criteria for flaw detection, sizing and evaluation;
- Inspection procedures; and
- Technical Justifications (TJs) which document how the inspection procedure satisfies the Inspection Specification.

Under COG Joint Project JP-4027, OPG-N and its partnering CANDU utilities have prioritized qualification work, with a focus on establishing a first level of qualification documentation for major inspection procedures. It is intended that work on inspection qualification be implemented in phases, with lessons learned integrated into future activities. The CANDU Inspection Qualification Bureau (CIQB) has been established within the CANDU Owners Group (COG) to provide an independent assessment of the adequacy of qualification documentation and assess the qualification of inspection procedures and personnel. Under COG JP-4027, Inspection Specifications in the areas of fuel channels, piping, feeders, and piping & vessel welds will be produced for subsequent inspection qualification work to proceed.

The industry initiative for inspection qualification has been under discussion with the CNSC, including an informal meeting held in January 2006, and the CNSC has provided verbal endorsement of the ENIQ qualification approach. OPG-N has recently drafted a follow-up letter to the CNSC indicating intent to follow through on this industry initiative.

Management will need to assign dedicated capable staff to ensure meeting the targets of the Project. The majority of the resources required for this project will be from IM&CS. Some support will be required from E&M (Engineering Services Division, Science & Technology Division) to expedite the Inspection Specifications (engineering requirements) with COG, as these are pre-requisites to planning the qualification work. This is a long-term project, which requires continual support of its priority since there will be scheduling conflicts with respect to IM&CS and E&M outage support commitments. Inspection Qualification work and results, with potential changes or impacts on the scope and techniques of inspections at the stations, need to be communicated to the stations in a timely manner.

<u>References</u>:

[1] J. Baron, et al, N-REP-04160-10000-R00 "NDE Performance Demonstration Pilot Project," dated May 29, 2001.
[2] NSS Report GC006/RP/002-R01, "Report on Performance Demonstration of NDE Techniques for the Canadian Nuclear Safety Commission," dated April 2005.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
OM&A	-	(10,532)	(9,841)				
Capital	-	(4,200)	(4,200)				
NPV (after tax)	-	(9,661)	(9,195)				
Impact on Economic Value (IEV)	N/A	(9,661)	(9,195)				
IRR%	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Stop the Project - Not Recommended

Stopping the project is not recommended as CNSC expects sustained progress on this regulatory requirement. The other COG utilities have also supported the need to progress Inspection Qualification. CIQB has already been established within COG, ready for qualification of inspection service providers. Lack of progress in this project could result in a CNSC regulatory action.

Alternative 1 - Advance the project with partial releases - Recommended

Since the ISs, technical specification and scope of IQ work are still being developed, two partial release BCSs are recommended for 2009 and 2010-2011 activities so that the project risks are reduced, as required information is produced. A final release BCS will be submitted for 2012 activities to complete the project.

Alternative 2 - Delay Project - Not Recommended

We do not recommend delaying the project as the Industry (including OPG) has already communicated a planned progress to the CNSC at a meeting in June 2008. OPGN is expected to show progress to the CNSC in the next upcoming project status update in June 2009. Project delay could lead to regulatory action to force work on an accelerated schedule and increased cost.

Alternative 3 – Do Less - Not Recommended

Meeting nuclear industry good practices for inspection qualification, proposed in ENIQ methodology, is in fact the minimum OPG should do. For the most part, OPG and the CANDU industry have not been compliant with the good practices established by the international nuclear industry for inspection qualification over the last decade.

Alternative 4 – Do More - Not Recommended

Doing more than industry good practices will not provide significant additional benefit but would incur more cost. Also, with uncertain availability of resources and information about the technical specification and scope of work, taking on accelerated or augmented scope is not recommended.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

We propose a staged funding strategy as follows:

Includes contingency

Owner	LTD 2008 (Phase 1)	2009 (Phase 2)	2010-2011 (Phase 3)	2012 (Phase 4)
EMD	**$250k OM&A LTD** to: • Manage the project • Develop charter & BCS • Oversee the activities of IM&CS, COG & CIQB • Review/comment on IS, & IM&CS IQ-PEPs/work	**$100k OM&A** to: • Manage the project • Oversee the activities of IM&CS, COG & CIQB • Review/comment on IS, & IM&CS IQ work • Develop PR-BCS	**$200k OM&A** to: • Manage the project • Oversee the activities of IM&CS, COG & CIQB • Review /comment on IS, & IM&CS-IQ work • Develop final release BCS	**$50k OM&A** to: • Manage the project • Oversee the activities of IM&CS, COG & CIQB • Review/comment on IM&CS IQ work • Prepare close-out report
IM&CS	**$812k OM&A LTD ($36k in 2007 & $776k in 2008)** to prepare/issue PEPs for IQ-work and preparation of IQ dossiers **$100k Capital LTD** to purchase software/samples	**$2222k OM&A** to prepare IQ documents [Technical Justification (TJ), Inspection Procedure (IP), training material, impact reports] **$1400k Capital** to purchase IQ specimens, mock-ups, probes, samples, software	**$3931k OM&A** to prepare/submit IQ dossiers to CIQB **$2700kCapital** to purchase IQ specimens, mock-ups, probes, samples, software	**$1547k OM&A** to prepare/submit IQ dossiers to CIQB
COG	**$[redacted] OM&A LTD** to: • Develop/issue ISs in the areas of FC, Piping and SGs	**$[redacted] OM&A** to: • Develop/revise new/old ISs in other IQ areas • Develop common IPs	**$[redacted] OM&A to:** • Develop/revise new/old ISs in other IQ areas • Develop common IPs	
CIQB	**$[redacted] OM&A LTD** to establish CIQB organization & governance for IQ of ISPs	**$[redacted] OM&A** to prepare for and review IQ documents submitted by the industry	**$[redacted] OM&A** to qualify IM&CS based on submitted IQ dossiers	**$[redacted] OM&A** to qualify IM&CS based on submitted IQ dossiers
OM&A	**$1432k**	**$2622k**	**$4731k**	**$1747k**
Capital	**$100k**	**$1400k**	**$2700k**	**0**

5/ QUALITATIVE FACTORS

Inspection Qualification will assist in optimization of fitness-for-service decisions, Life Cycle Management (LCM) strategies, and business risk assessments by providing confidence in, and improved understanding of, the capability of inspection procedures and personnel to detect and size flaws. The benefits of qualification will apply to both Pickering and Darlington.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
PARTIAL RELEASE BCS's Cost underestimation. (The inspection qualification process is a new endeavour for both COG and the utilities. The level of effort and resourcing is difficult to predict.)	Costs and schedule exceed estimate	**Medium**	Adopt phased approach (several partial release BCSs) with high level of management oversight, while better definition and selection of achievable scope of IQ work and detail resource planning is achieved.	**Low**
TOTAL PROJECT Cost risk is linked to Scope, Schedule and Resource issues listed below	See Below		See Below	
The estimates assume ~2 M$ contribution from [redacted] and/or other utilities for cost-sharing.	Costs could increase if [redacted] and/or other utilities are unable or unwilling to participate in cost-sharing.	**Medium**	The [redacted] M$ contingency would cover the additional 2M$ that may be required to offset the lack of [redacted] participation to sahre the costs.	**Low**
Scope				
IQP could require increased effort to produce acceptable results. Current estimates of effort may not be accurate (The inspection qualification process is a new endeavour for both COG and the utilities. The level of effort and resourcing is difficult to predict). Unanticipated issues may arise during the project resulting in scope creep, cost over-run, schedule delay	Scope creep, schedule and cost overrun	**High**	High level of management oversight over COG & IM&CS plans/progress, through Inspection Qualification Project Steering Committee (IQPSC) with phased approach in development of a high quality project execution plans (PEPs) for each inspection area (FC, Feeders, SGs & piping) followed by partial release BCSs for the detailed scope of worked and planned resources. Any increase or change in the scope to be managed using Change Management Process, PM principles, and/or a superseding BCS. The large (60%) contingency on cost reduces the risk to	**Medium**

			medium. IMS is to allocate additional internal resources during non-peak or non-emergent work periods and also obtain contracted resources where existing resources are unavailable. Effective planning and scheduling of the work and assignment of resources, together with the maintenance of a detailed resource-loaded schedule, will provide the necessary project management controls to minimize schedule slippages.	
Schedule				
Schedule prone to slippage due to reliance on external suppliers (COG, its sub-contractors, and participating utilities) for industry inspection specs and on IM&CS, and engineering resource availability; given that outage work takes priority in IM&CS and EMD, considering that the staff working on this project mostly support outage inspection work.	Underspend in short term, but longer term cost overrun, schedule delay	**High**	Same strategies adopted for scope risks should reduce the risk from High to Medium.	**Medium**
Resources				
The bulk of IM&CS and Engineering resources are often tied up on outage work, and hence resource availability for project work is uncertain.	Schedule delay	**High**	Same strategies adopted for scope risks should reduce the risk from High to Medium.	**Medium**
Technical				
Existing inspection procedures/ technology may	Current procedures or equipment may require modification in order to pass	**Medium**	Lack of capability would be evaluated as part of our fitness-for-service assessment	**Medium**

not be qualifiable per the inspection spec requirements. The OPG-N Pilot Project demonstrated a difficulty with conventional UT sizing to meet the ferritic pipe weld inspection spec	successfully through the IQ process. This may further impact the need for training. In some cases, inspections performed to date may be considered less-than-adequate, and this may be construed as failure of licensee to meet CSA N285.4 Clause 3.6e, which could be S-99 Reportable. IQP information would be of critical value to OPG-N, to identify those elements that require improvement. Potential costs and delays due to this have not been and are not easy to assess due to lack of adequate information at this stage and so are not accounted for in this BCS.		and disposition process. Development of enhanced inspection capability may be required (not costed here). Minor changes to NDE procedures or to training processes may be covered by the IQP contingencies. Financial mitigation of larger issues is beyond the scope of the IQP. As with any discovery issue, depending on urgency and implications, OPG should be prepared to initiate a project to develop and qualify alternate procedures. For a generic issue, such work could be cost-shared within the CANDU industry e.g. as a separate COG Joint Project.	
Regulatory				
Qualification of NDE procedures and resources may be challenged by the regulator.	If not defensible, some inspections performed to date may be considered less than adequate. Could be construed as failure of licensee to meet CSA N285.4 Clause 3.6e, which could be S-99 Reportable.	**Medium**	Maintain frequent interaction and progress update with the regulator. Ensure qualification work is robust and defensible. Maintain adequate governance and QA to ensure quality end product technically correct and auditable project execution.	**Low**
Some existing procedures may not be qualifiable	Some inspections performed to date may be considered less-than-adequate. Could be construed as failure of licensee to meet CSA N285.4 Clause 3.6e S-99 Reportable.	**Medium**	Be prepared to develop and qualify alternate procedures (e.g. phased array procedures for pipe weld inspection) on an accelerated basis. Level 2 SCRs will be raised to immediately address any shortcomings with regulatory (safety) implications.	**Low**
Project delays	Rate of progress may be considered unacceptable, and regulator could impose deadlines.	**Medium**	Ensure appropriate management oversight (through IQPSC) and resourcing to maintain progress, and regularly provide the CNSC with progress reports.	**Low**
Environmental				
N/A		**N/A**		**N/A**
Health & Safety				
Conventional safety risks	Potential for injury.	**Low**	Adherence to Safety Policies, Governance,	**Low**

associated with operation of inspection equipment and handling specimens.			procedures, controlled access, personal protective equipment, pre-job briefings, etc.	
Investment				
Likelihood that this project will not meet the Business Objectives	Restart the project with considerable extra cost	**Low**	As this is an industry initiative (with significant portion under COG) and closely monitored by the regulator, there is little chance that this project will not meet its regulatory objectives.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	Oct 2013	Oct 2014	VP Science & Tech. Development

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" **Glossary (acronyms, codes, technical terms)**

- **CIQB -** CANDU Inspection Qualification Bureau - An organization established within COG and authorized by its participants, to prepare, administer and conduct examinations to qualify NDE procedures and personnel with respect to the nondestructive inspection of CANDU nuclear plants.
- **COG** – CANDU Owners Group
- **COG JP-4027** – COG Joint Project 4027 on Inspection Qualification for establishment of the **CIQB** and development of Inspection Specifications.
- **CSA** – Canadian Standards Association
- **CSA N285.4** – CSA Standard for Periodic Inspection of CANDU Nuclear Power Plant Components
- **Defect -** A flaw which requires remediation or mitigation for the component or system to be serviceable. CSA N285.4 defines a defect as "an unacceptable indication" (1994 Edition) and as "a flaw that cannot be dispositioned for further operation without repair or replacement" (2005 Edition).
- **ENIQ** – European Network for Inspection Qualification
- **EMD, E&M** – Engineering and Modifications Branch
- **ESD** - Engineering Services Division
- **FC** – Fuel Channel
- **FIJP** – Feeder Integrity Joint Project
- **Flaw -** An imperfection of the material or component that may or may not represent a deleterious condition. CSA N285.4 2005 edition defines a "flaw" as "an indication that does not meet the acceptance criteria of this Standard".
- **Indication** - an instrument output or display which requires assessment as (i) not being related to the condition of the component or material, or (ii) an imperfection of the material or component. CSA N285.4 2005 Ed defines an indication as "relevant evidence or signal of deterioration, as revealed by a nondestructive test."
- **IM&CS** - Inspection Maintenance & Commercial Services
- **IP -** Inspection Procedure: An orderly set of instructions to be followed by a properly qualified NDE practitioner in order to conduct a nondestructive examination of a material, component or system.
- **IQ** – Inspection Qualification
- **IQ dossier** - packages that include Inspection Specification, Technical Justification, IPs plus training and test programs/tools)
- **IQP** - Inspection Qualification Project – this project.
- **IQPSC** - Inspection Qualification Project Steering Committee
- **ISP** - Inspection Service Provider: An organization or individual that conducts nondestructive examinations, typically on contract to the owner or licensee of the CANDU plant to be inspected.
- **IS** - Inspection Specification: A document that identifies and specifies the required capabilities of a nondestructive examination process.
- **ISD** – Inspection Services Division – previous name of IM&CS.
- **NDE** - Nondestructive Examination: A process where materials, mechanical components and systems are examined and evaluated, typically for degradation mechanisms but also for dimensional measurement, whereby the examining medium does not cause or require degradation of that being examined. Examples of NDE methods are: radiography, ultrasound, dye penetrants, magnetic particles, eddy current, acoustic emission, radar and visual inspection.
- **PEP** – Project Execution Plan
- **PDI** - -Performance Demonstration Initiative
- **PIP** - Periodic Inspection Program
- **PR** – Partial Release
- **PROL** – Power Reactor Operating License
- **QA** – Quality Assurance
- **Qualification** - the process by which an inspection procedure, or an individual inspector, is evaluated against defined performance requirements

- **S&TD** - Science & Technology Development Division
- **SG** – Steam Generator
- **TJ** - Technical Justification - A document that sets out a cogent technical argument whereby a particular Inspection Procedure meets the requirements of a particular Inspection Specification.
- **UT** – ultrasonic testing

Appendix "B"

Project Funding History

66105 OM&A

$ 000's OM&A Release Type	Month	Year	Releases (incl contingency) Cumulative Values								
			2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	10	2006	1,200								1,200
Partial	11	2008	332	1,100	2,622						4,054
Partial	11	2009	332	1,100	2,622	2,400	1,000				7,454
Full	5	2011	332	1,100	2,622	2,400	2,331	1,747			10,532
											0
											0
											0
											0

LTD Spent	11		332	691							1,023

62552 Capital

$ 000's Capital Release Type	Month	Year	Releases (incl contingency) Cumulative Values								
			2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	11	2,006		200							200
Partial	11	2,008		100	1,400						1,500
Partial	11	2,009		100	1,400	1,400					2,900
Full	5	2,011		100	1,400	1,400	1,300				4,200
											0
											0
											0
											0

LTD Spent	11	08	0	0							0

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

The total project cost estimate of $14.7M ($[redacted] is based on a recent IM&CS estimates taken from the detail PEPs (attached to this BCS) developed for five area of inspection qualification activities.

	Old ISD Estimate M$ (2002) [3,4]	Current Estimates M$ (2008)	Variance	Comment
DQO (Labour + Material)	2.4	0.0	(2.4)	DQO is now CIQB (COG), planned under the next line item
CIQB and COG JP-4027	0.0	1.4	1.4	DQO is now CIQB, with some costs shared under JP-4027. ~200k$ of original work already complete
Engineering	0.6	0.6	00	
IM&CS (OM&A)	8.0	9.2	1.2	The new estimates are based on the recently developed PEPs
IM&CS Bruce-specific work (SG)	1.0	0.0	(1.0)	Removed
Material (IM&CS)	1.0	3.5	2.5	The new estimates are based on the recently developed PEPs, which provide a more accurate picture of the material and tools to achieve qualification in each area with required technologies.
Potential cost sharing	0.0	(2.0)	(2.0)	With [redacted]other CANDU Utilities
Total	13.0	12.7	(0.3)	Project is therefore implemented at lower costs provided cost sharing in development of IPs with other Candu Utilities. However, if such cost sharing is not possible, the new total project cost estimate is 14.7, which is $1.7M higher than original estimates.

The 2002 ISD estimates [Ref 3, 4] given above were based on full-costed ISD labour rates and included a 2%/year escalation factor. A [redacted]% contingency was used for risk mitigation. For the current BCS, a general contingency of [redacted]% is assumed to mitigate numerous identified risks associated with the development and implementation of the project.

So far, the project has spent $1532 to establish CIQB, develop ISs and IQ-PEPs in four major areas of inspections. This partial release BCS includes the IM&CS PEPs estimates for development and revision to IM&CS IQ documents, OPG share of COG costs for IS revisions and the IQ activities of CIQB. OPG share of the annual CIQB retainer fee ($180k per year) is paid from the base OM&A of Technology & Research annual budget

References:

[3] – E-mail, B. Bevins to S. Powers, P. Spekkens, "Qualification of NDE PEP and BCS," 2002-12-18. (includes the Attachment draft OPG BCS, "Qualification of Non Destructive Examination Processes," dated September 23, 2002).

[4] – E-mail, E. Cartar to file, "Adjusted Inspection Qualification BCS Costs with Corrected ISD Labour Rates," (includes attachment Excel Spreadsheet, December 2002, showing increased total cost to 13M$ from 12.6 M$ to reflect corrected ISD labour rates for technicians).

Financial Assumptions:

NPV Discount factor = 7%

The original estimates assumed cost escalation of ~2% per annum and these have been retained in the current estimates.

Project / Station End of Life Assumptions:

N/A

Energy Price / Production Assumptions

N/A

Operating Cost Assumptions

N/A

Other Assumptions:

Note: for work identified as part of COG Joint Project, OPG's share is 33-40% of the cost, depending on the participation of other utilities.

Participation of [redacted] other CANDU utilities (e.g. through a COG Joint Project) could result in a cost reduction of 2M$. Details on aspects of the IQP that might be cost-shared with other utilities have not yet been worked out.

Inspection Qualification (Capital) 10 - 62552

Developmental Release Business Case Summary N-BCS-04160-10000-R000

Attachment "A1" **Project Cost Summary**

$000's Capital	LTD Prior Yr 2007	This Release 2008	This Release 2009	This Release 2010	Future Release 2011	Future Release 2012		Later	Total
Project Management (OPG)									-
Engineering & Drafting (OPG)									-
Material									-
Installation – PWU, BTU									-
Contract - Design									-
Contract - Installation									-
Contract - Other									-
IMS (Capital Costs)		100	900	900	800				2,700
									-
Interest (Capital Project Only)									-
Project Costs (excl contingency)	-	100	900	900	800	-	-	-	2,700
General Contingency			500	500	500				1,500
Specific Contingency									-
Project Costs (incl contingency)	-	100	1,400	1,400	1,300	-	-	-	4,200
2009-2013 Business Plan		100	500	800	800	500			2,700
Variance to Business Plan	-	-	400	100	-	(500)	-	-	-
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	100	900	900	800	-	-	-	2,700
Total Release (incl contingency)	-	100	1,400	1,400	1,300	-	-	-	4,200

Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	N/A		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	No
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	No	Contracts in place	Yes	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By:

K Rassouli

Kazem Rassouli
Project Manager

Date:

Approved By:

Paul Spekkens Jan 6, 2009

Paul Spekkens, VP S&TD
Eng & Mods Manager (Strat IV)

Date:

Project Name 10 - 62552 OM&A 10 - 66105

Developmental Release Business Case Summary N-BCS-04160-10000-R000

Attachment "A2"

Project Cost Summary

$000's OM&A	LTD Prior Yr 2007	This Release 2008	This Release 2009	Future Release 2010	Future Release 2011	Future Release 2012		Later	Total
Project Management (OPG)	50		20	20	20	10			120
Engineering & Drafting (OPG)	200		80	80	80	40			480
Material									-
Installation – PWU, BTU									-
Contract - Design									-
Contract - Installation									-
Contract - Other									-
IMS (OM&A)	82	[redacted]							
COG		[redacted]							
Interest (Capital Project Only)									-
Project Costs (excl contingency)	332	[redacted]							
General Contingency		[redacted]							
Specific Contingency		[redacted]							-
Project Costs (incl contingency)	332	1,100	2,622	2,400	2,331	1,747	-	-	10,532
2009-2013 Business Plan	332	[redacted]							
Variance to Business Plan	-	(66)	-	-	-	66	-	-	-
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	332	[redacted]							
Total Release (incl contingency)	332	1,100	2,622	2,400	2,331	1,747	-	-	10,532
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	N/A		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	N/A	OPEX used	Yes	Lessons Learned	No
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects	No	Contracts in place	Yes	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2006-2010 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By:

Approved By:

Paul Spekkens Jan 6 2009

Inspection Qualification Project 10 - 62552

Developmental Release Business Case Summary N-BCS-04160-10000-R000

Attachment "B1" **Project Variance Analysis**

Capital	LTD Nov 2008	Choose One: Last BCS Nov 2006	Choose One: This BCS Nov 2008	Variance	Comments
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material	100	[redacted]			
Installation – PWU, BTU				0	
Contract - Design				0	
Contract - Installation				0	
Contract - Other				0	
IMS (PEPs & IQ dossiers)				0	
COG (Ins. Specs/Proc., CIQB)				0	
Interest (Capital Project Only)				0	
Project Costs (excl contingency)	**100**	[redacted]			
General Contingency	**0**	[redacted]			
Specific Contingency				0	
Project Costs (incl contingency)	**100**	**4200**	**4200**	**0**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**100**	**4200**	**4200**	**0**	
Total Release (excl contingency)	**100**	[redacted]			

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Comments:

Inspection Qualification Project 10 - 66105

Developmental Release Business Case Summary N-BCS-04160-10000-R000

Attachment "B2" **Project Variance Analysis**

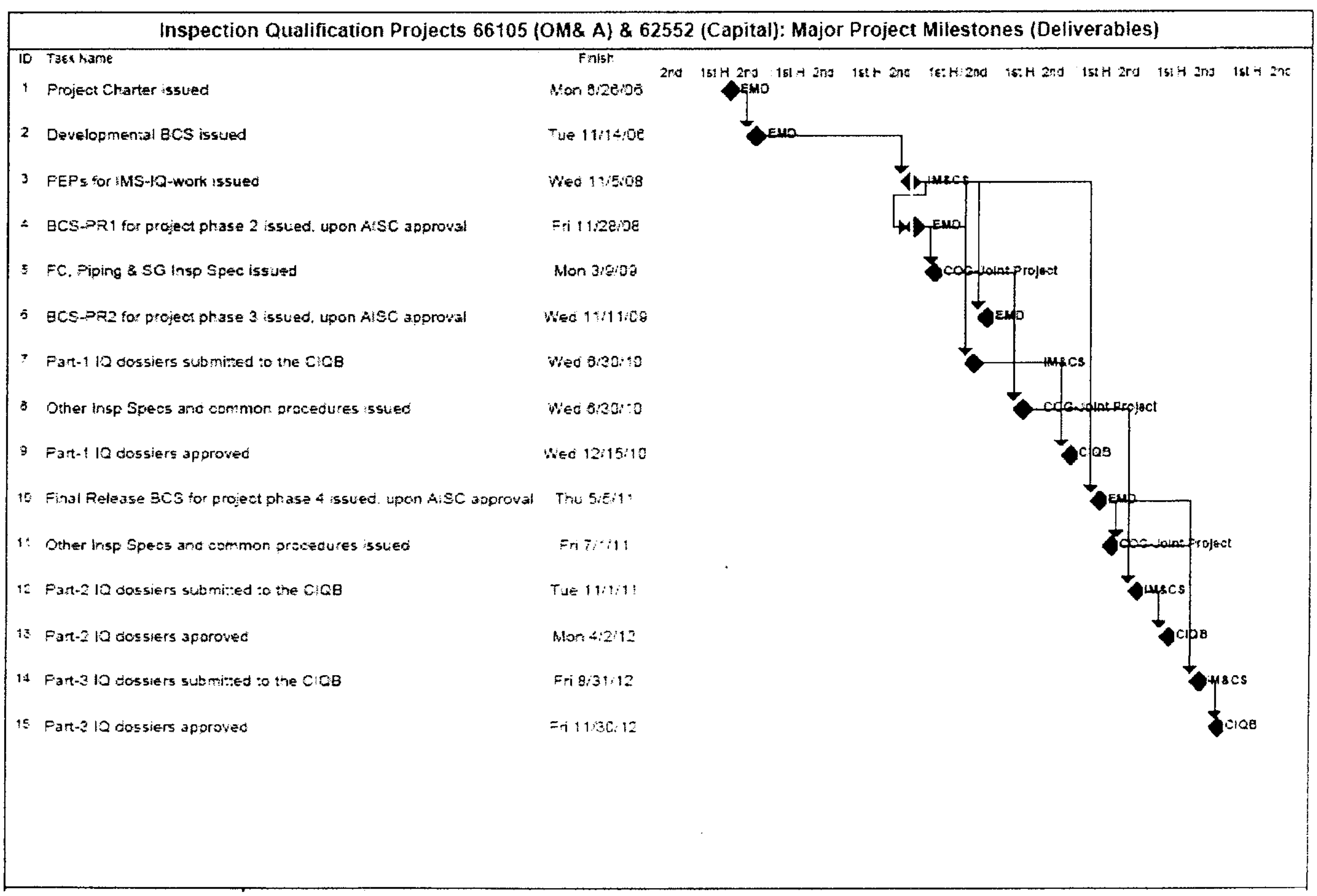
OM&A	LTD Nov 2008	Choose One		Variance	Comments
		Last BCS Nov 2006	This BCS Nov 2008		
Project Management (OPG)	50	200	120	-80	
Engineering & Drafting (OPG)	200	720	480	-240	
Material				0	
Installation – PWU, BTU				0	
Contract - Design				0	
Contract - Installation				0	
Contract - Other				0	
IMS (PEPs & IQ dossier)	612	[redacted]			
COG (Insp. Specs/Proc, CIQB)	370	[redacted]			
Interest (Capital Project Only)				0	
Project Costs (excl contingency)	**1232**	[redacted]			
General Contingency	**200**	[redacted]			lower risk due to work completed
Specific Contingency				0	
Project Costs (incl contingency)	**1432**	**10800**	**10332**	**-468**	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	**1432**	**10800**	**10332**	**-468**	
Total Release (excl contingency)	**1232**	[redacted]			

Ongoing OM&A (non-project)				**0**	
Removal Costs (incl in above)				**0**	

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
26	Jun	2006	Project Charter issued (EMD)
14	Nov	2006	Developmental BCS issued (EMD)
5	Nov	2008	PEPs for IMS-IQ-work issued (IM&CS)
28	Nov	2008	BCS-PR1 for project phase 2 issued, upon AISC approval (EMD)
9	Mar	2009	FC, Piping & SG Insp Spec issued (COG-JP)
11	Nov	2009	BCS-PR2 for project phase 3 issued, upon AISC approval (EMD)
30	Jun	2010	Part-1 IQ dossiers submitted to the CIQB (IM&CS)
30	Jun	2010	Other Insp. Specs and common procedures issued (COG-JP)
15	Dec	2010	Part-1 IQ dossiers approved (CIQB)
5	May	2011	Final Release BCS for project phase 4 issued, upon AISC approval (EMD)
1	Jul	2011	Other Insp Specs and common procedures issued (COG-JP)
1	Nov	2011	Part-2 IQ dossiers submitted to the CIQB
2	Apr	2012	Part-2 IQ dossiers approved
31	Aug	2012	Part-3 IQ dossiers submitted to the CIQB
30	Nov	2012	Part-3 IQ dossiers approved

A Project Execution Plan (PEP) will be approved by Nov 2008



Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A
Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

1/ RECOMMENDATION:

Approval is requested for the Full Release of $53.2M Capital (including contingency) and $[redacted] OM&A (specific contingency) to proceed with the next stage of the Weld Overlay Project which will design and manufacture weld overlay tooling for those Darlington outlet feeders that are life-limited by pipe wall thinning caused by Flow Accelerated Corrosion (FAC). This brings the total costs to $71M.

The business objective of this project is to reduce the cost of managing life-limiting feeder thinning by developing a repair alternative to the current exclusive use of Cut and Weld tooling for replacing thinned feeders. It is estimated that using weld overlay repair technology in conjunction with Cut & Weld tooling (as necessary), will provide a financial benefit in the range of approximately $38M - $143M (NPV) with a 19% – 45% IRR. (See Alternative Section for details). This estimate is based primarily on the assumptions:

- Less overall time required to repair a feeder during a Darlington outage
- Lower execution costs per feeder repair

To date, there has been four partial releases for Weld Overlay under project # 62435 (OM&A): $1.5M in 2005-2006 for the Definition stage (Proof-of-Concept); $700K in 2006-2007 for the Pre-Tool Development phase, $3.7M in 2007 for Stage I (Preliminary Design of Tool and process) and; $10.6M in 2008 to complete Stage I which is in progress. The project is currently managing Stage I Preliminary Design contracts with two separate vendors in an effort to maximize the probability of project success.

A 2011 Darlington Spring Outage In-service date for this process and tool significantly increases its economic benefits, which necessitates seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates included in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a large amount of contingency has been assigned in this BCS to account for the uncertainty.

At the end of Stage I, a revised BCS will be prepared with updated project costs within the value of this release request, and updated risks to reflect the work completed in Stage I. The project team will present the technical and business case as a formal recommendation in a decision meeting, chaired by the CNE (see Attachment D). This revised BCS will be presented for signature during this decision meeting with the CNE, and follow up meetings with the CNO, COO, and CEO. If approved, only the value in the revised BCS will be released. At this time, outage savings will be quantified for 2010 - 2014 business planning. P4[illegible]

$000's (incl contingency)	Funding	Type	LTD 2008	2009	2010	2011	2012	Later	Total
Currently Released	Partial	OM&A	3,647	12,887					16,534
		Capital							-
Requested Now	Full	OM&A			1,000				1,000
		Capital		5,050	45,060	3,084			53,194
Future Funding Req'd	N/A	OM&A							-
		Capital							-
Total Project Costs			3,647	17,937	46,060	3,084	-	-	70,728
Other Costs									-
Ongoing Costs									-
Grand Total			3,647	17,937	46,060	3,084	-	-	70,728

Investment Type	Class	NPV	IRR	Discounted Payback
Value Enhancing	Capital & OM&A	38M - 143.4M	19% - 45.5%	5 - 3 Years

Submitted By:

T. Mitchell
Chief Nuclear Officer
Date:

Finance Approval:

D. Hanbidge
S.V.P. & Chief Financial Officer
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

J. Hankinson
President & Chief Executive Officer
May 15/09
Date:

2/ BACKGROUND & ISSUES

Degradation of primary heat transport system feeders by flow-accelerated corrosion (FAC) is a significant life-limiting threat to OPG Nuclear plants. Cut and weld methods currently used for replacement of thinned feeder sections requires a number of preparatory activities (including channel defuelling, isolation and draining) that cannot be completed in parallel. As the number of feeders to be replaced increases, the time required to complete the repairs has a more significant impact on the duration of planned outages.

Another approach to feeder repair is to build up the feeder wall thickness by weld overlay, which deposits a layer of weld metal on the exterior of the pipe work. Advantages of this method include elimination of the need to defuel and drain the channel, a potential reduction in the time required for repairing each feeder, as well as an anticipated reduction in worker radiation dose and the amount of loose contamination and radioactive waste produced.

Weld overlay is a demonstrated technology that has been used successfully in both nuclear and non-nuclear repair applications. This current proposed application of the technology is considered a first of a kind due to the specific conditions of the repair. These include, that it is to be performed on thin wall, carbon-steel nuclear class 1 piping with specific material property requirements; it is to be applied with very tight clearances making tooling design difficult, and the pipe will be full of water during the application. In the original proof of concept study, weld overlay was demonstrated as being feasible for these specific conditions, however residual technical risks were identified. These risks include material properties (hydrogen, hardness, and residual stress), and miniaturization of the tooling.

During Stage I Preliminary Engineering (currently in-progress), the residual risks identified during the proof of concept work are being addressed. Weld processes are being developed to enhance favourable material properties, inspection techniques are being developed for pre and post overlay requirements, and a conceptual tool design will be provided based on tooling requirements and available clearances at the feeder hub to pipe weld area. Two vendors are currently contracted in competitive, parallel efforts to successfully complete Stage I in order to maximize the probability of project success.

A 2011 Darlington Spring Outage in-service date for this process and tool significantly increases its economic benefits, which necessitates a seamless transition into Stage II of the Weld Overlay Project. For this reason, this request for Capital funding approval is being made prior to the completion of Stage I, and prior to estimates being provided by the vendors. The budgetary estimates provided in this request are based on costing experience with the similar Cut and Weld tooling, and are considered conservative. Also, a [redacted]% contingency has been assigned in this BCS to account for the uncertainty.

At the conclusion of Stage I, an updated economic analysis and revised BCS will be prepared using vendor provided budgetary estimates for Stage II, and a formal decision meeting will be held to determine whether to recommend proceeding with weld overlay tool detailed design and manufacture. The basis for the decision meeting may be found in Attachment D. If a recommendation to proceed is decided, a second decision meeting will be held with the CNO to present the case and obtain his acceptance. The CNO will then take the recommendation to the COO and then to the President for approval and final release.

The Weld Overlay Project is being executed in two stages as detailed in the table below. This staged funding release and execution is being used to minimize the financial risk, and provide adequate assurance that the repair technique and tooling is technically acceptable.

Stage 1 (OM&A) consists of: Proof of Concept (complete); Pre-Tool Development (complete); and Preliminary Engineering (in progress). To date, the concept of weld overlay has been demonstrated as a feasible repair technology and residual technical risks have been identified. The Preliminary Engineering phase will resolve the technical risks which involve primarily material property issues, and will provide a conceptual tool design.

Stage 2 (Capital) consists of three distinct phases: Detailed Design & Prototype Fabrication; Fabrication & Mock Up Testing; and Commissioning. At the end of this stage of the project, the tool sets will be declared as Available For Service, Regulatory approval will have been granted, and multiple tool sets ([redacted] currently projected) will be available for use at Darlington.

Stage / Cost Type	Phase	Cost Area	Cost Item	Estimated Cost (K$ CND) Includes Contingency 2005	2006	2007	2008	2009	2010	2011	Total
1 OM&A	1	Proof-Of-Concept	Develop Concept and identify major risks	1,275	145						1,420
		Pre-Tool Development	Development of tool requirements.		260	370					630
		Preliminary Engineering (Currently in Progress)	Material Property Issue Resolution, Preliminary Design - Tool / Process			127	1,470	12,887			14,484
2 Capital	2	Detailed Design & Prototype Fabrication	Tool Development & Commissioning					5,050	45,060	3,084	53,194
	3	Fabrication & Mock Up Testing									
	4	Commissioning									
2 OM&A	(OM&A Specific Contingency)								1,000		1,000
				1,275	405	497	1,470	17,937	46,060	3,084	70,728

A total of $53.2M Capital (including contingency) and $1M OM&A (specific contingency) is requested to perform Stage II of the Weld Overlay project. This release request includes a $[redacted]M specific contingency to cover uncertainties regarding applicability of PST which is dependent on Tool ownership (title) by OPG or entry of a non-OPG owned tool into Ontario which may be built in the USA. Applicability of PST will not be known until the successful completion of Stage I; therefore, [redacted]% of tool development costs have been reserved in a specific contingency. This funding will only be released if PST is required.

This release request also includes a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010. If the feeder is repaired and left in-service, it is Project OM&A; if it is repaired and cut out it is Project Capital. At this point in the project, it has not been decided whether the feeder will be left in service or cut out.

This full release business case summary and the associated economic analysis ("Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002", N-REP-30751-10007) considers only the weld overlay candidates at Darlington based on the latest feeder replacement schedule. The analysis assumes that weld overlay repair will be performed on the feeder repair candidates from 2011 onward.

Since the original Economic Analysis assessment in 2007, the 6 probe inspection results at Darlington have shown an increased number of feeders that have life limiting thinning in the Grayloc area (as projected in N-BCS-30751-100000-R000) which considerably strengthens the economic viability of this project with the additional funding requested. As well, 6 probe inspections for all Darlington units are not yet complete and may reveal additional life limited thinned feeders.

This project includes only the costs associated with developing, delivering and commissioning the Weld Overlay tooling. Weld Overlay field application costs will be addressed outside this project; however, these projected (listing estimates) costs have been included in the NPV calculations.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

The economic benefit of introducing weld overlay tooling is presented in this BCS as a potential NPV range. This approach was taken for the following reason:

The actual number of feeders scheduled for repair in any given outage (until Unit end-of-life) can vary because of new inspection results and emergent repair requirements. There are currently two methods used for determining feeder repair candidates (Reference NK38-CALC-33160-10044):

1. **Current Assessment:** The current case provides the remaining life of feeders with the current assessed wall thinning rates as determined by the *rate from initial* methodology for feeders limited adjacent to the Grayloc weld. It is commonly assumed that the feeder pipe adjacent to the Grayloc weld began life at a wall thickness lower than that of nominal pipe thickness. Thus, the methodology is assumed to provide conservative estimates of the wall thinning rate.
2. **Risk Informed:** The risk informed method Incorporates all the information that is available for each feeder. As described, the formal feeder thinning assessment utilizes a single thinning rate to ensure conservatism in estimating remaining life. However, for replacement planning purposes it is recognized that over conservatism puts a strain on long term planning practices.

The Risk Informed method allows for a more realistic approach to determining which feeders require replacement, however, by reducing some of the conservatism, there is an inherent risk of under estimating thinning rates, which could result in emergent replacements. Because of this risk, and the risk of emergent replacement requirements coming from future inspections, two (2) separate economic analyses were conducted, using a set of feeder repair candidates derived from each estimating method. The result of each analysis (NPVs) represents the potential range of economic benefits/losses of introducing weld overlay tooling.

Risk Informed Scenario

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(265,956)	(145,853)	(145,853)	(157,929)			
OM&A	(170,802)	(125,618)	(121,971)	(126,299)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(201,308)	(165,731)	(163,233)	(170,893)			
Net Present Value (NPV)	**N/A**	**35,576**	**38,074**	**30,414**			
Internal Rate of Return (IRR) %	N/A	17.7%	19.1%	17.7%			
Discounted Payback (Yrs)	N/A	8.2	8.1	8.3			

Current Assessment Scenario

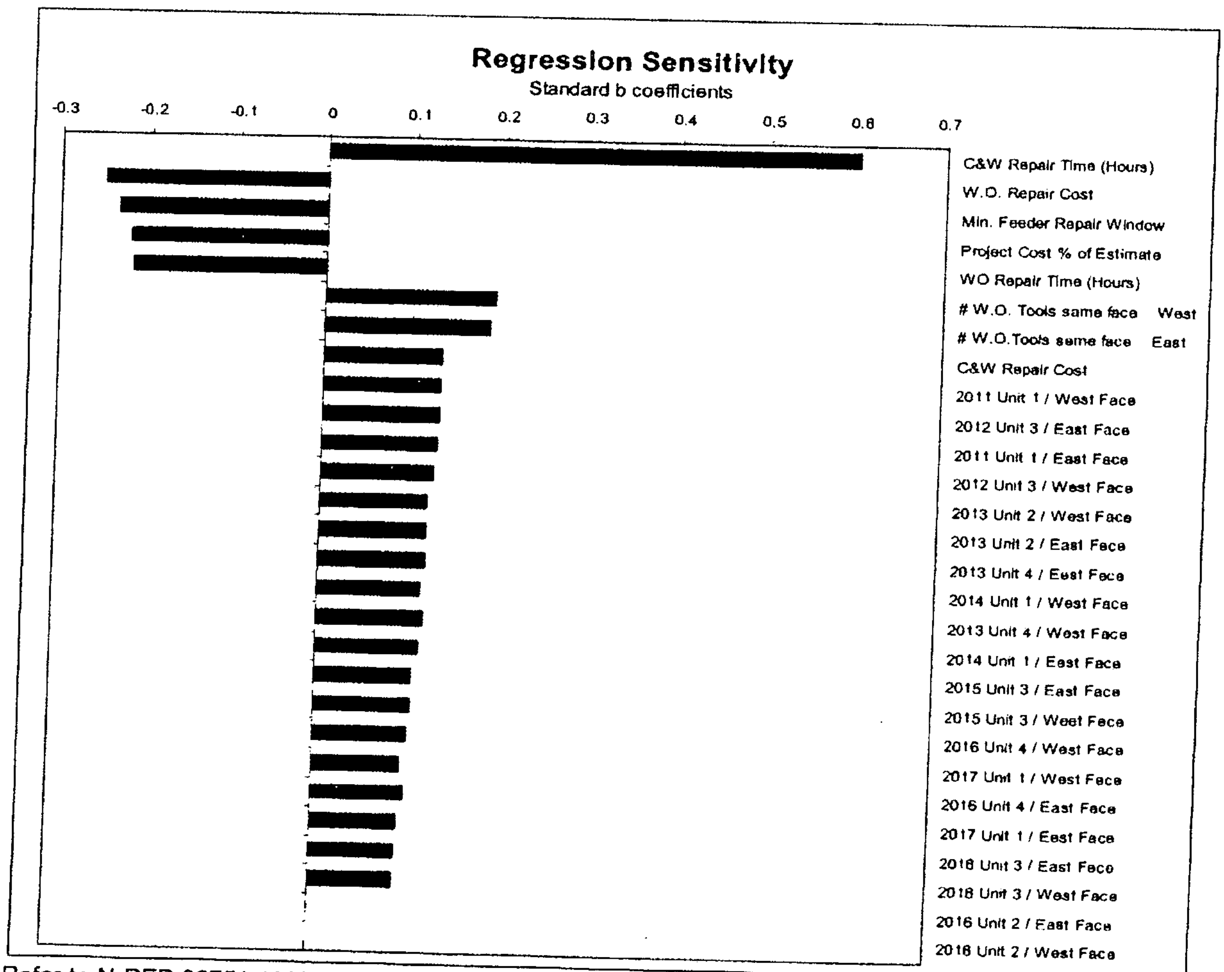
$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay Project (1 Year)	Alt 3	Alt 4	Alt 5
Revenue	(573,891)	(311,812)	(311,812)	(335,964)			
OM&A	(370,833)	(252,997)	(249,350)	(258,266)			
Capital	0	(51,205)	(51,205)	(51,205)			
Present Value (PV)	(451,016)	(310,114)	(307,616)	(325,336)			
Net Present Value (NPV)	**N/A**	**140,903**	**143,401**	**125,680**			
Internal Rate of Return (IRR) %	N/A	42.5%	45.5%	44.4%			
Discounted Payback (Yrs)	N/A	5.1	5.0	5.3			

Monte Carlo Simulation

The purpose of the analysis is to demonstrate the viability of Weld Overlay within the parameters of uncertainty that currently exist, before Stage 1 is complete. This was accomplished by completing a Monte Carlo simulation of the impact of Weld Overlay (versus Cut and Weld) using 28 variables that were identified as having the greatest impact on economic viability of the project.

Two Hundred Thousand (200,000) iterations were completed using @Risk software. The 28 variables were chosen randomly (for each iteration), within our best estimate of the parameters for each variable. The Monte Carlo analysis produced the following results:

Mean NPV = $72 Million
Maximum NPV = $233 Million
Minimum NPV = - $39 Million
There is a 90% confidence that the NPV will fall between $20 Million and $ 130 Million
The analysis produced 1,564 negative results
The analysis produced a tornado diagram ranking variable sensitivity. See below.



Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Base Case: Not Recommended - Stop the project

This is not recommended, as the exclusive use of Cut and Weld tools will result in lengthy outages during the peak replacement years that could jeopardize the Darlington Business Plan and the Darlington target of 38-day outages.

Alt. 1: Recommended - Proceed with Stage II of the Weld Overlay project

It is recommended to proceed with the release of $53.2M Capital (including contingency) and $[redacted]M OM&A (specific contingency) to award and execute a contract for Stage II of the Weld Overlay project. This technology will provide an alternative feeder repair option for repairing thinned areas, with an expected reduction in:

- Overall time required to repair a feeder
- Execution cost of feeder repair
- Production and safety risks associated with breaking the pressure boundary (See Qualitative factors)

It is estimated that using Weld Overlay tools in conjunction with Cut and Weld tools (as required) starting in 2011 will provide a financial benefit of approximately $38M - $143M (NPV). At the conclusion of Stage I, an updated economic analysis will be prepared using vendor provided budgetary estimates for Stage II and a formal decision meeting will be held to determine whether to proceed with weld overlay tool development, therefore, limiting sunk costs should this project not prove beneficial.

This alternative includes a specific contingency of $[redacted]M capital to cover uncertainties regarding applicability of PST, as well as a specific contingency of $[redacted]M OM&A to deal with uncertainties regarding on-reactor commissioning in 2010.

Details of the proposal are presented in Section 4.

Alt. 2: Not Recommended - Delay project for 1 year

This alternative is not recommended because delaying the project will:

- Reduce the overall financial benefit by ~ $8M - $18M (NPV) if tooling is available for 2012 vs. 2011
- Increases the risk that, due to unforeseen issues in this R&D project, the tooling will not be ready when feeder repairs are most needed.
- Risk losing experienced team members and vendors to support tool development.

Alt. 3: Not Recommended - Include Pickering A and Pickering B

This is not recommended because:

- Pickering B has very few feeders that are candidates for weld overlay before end of life.
  Pickering A feeders may not benefit from grayloc-area overlay, as they have concerns with life-limiting thinning further downstream. The extent of downstream thinning and the potential benefit of grayloc-area overlay will become more apparent after further inspection programs are completed at Pick A. It would be advantageous to first develop the tooling for Darlington, and adapt the tooling for Pickering A later, as required.
- Both Pickering A and Pickering B have tighter clearances around the feeders, making tool design more challenging.

The NPV has not been shown for this alternative because of the uncertainty indicated above.

4/ THE PROPOSAL

Upon successful completion of Stage I (currently in-progress), a formal decision meeting will be conducted to determine whether to proceed with weld overlay tool development based on Stage I results and up to date Stage II budgetary estimates.

If tool development does not present a positive economic case or if Stage I was not able to resolve outstanding areas of technical risk, the project will likely be cancelled; otherwise, a revised BCS, within the value of this BCS, will be submitted for approval and used to award a contract for Stage II of the weld overlay tooling and processes development project for Darlington. Stage II will be executed in three (3) phases:

1. <u>Detailed Design and Prototype Fabrication</u>
   In this Phase, detailed documentation and drawings for the weld overlay tool and process will be prepared based on the parameters identified in Stage I.

   A prototype tool will be built and tested on a mock-up which will simulate real feeder configurations, feeder clearances and shutdown conditions.

   CNSC acceptance will be obtained for the weld overlay processes, analyses and inspections; as well as support for joint registration of the weld procedure with TSSA.

2. <u>Fabrication and Mock-up Testing</u>
   In this Phase, the Production Tools (up to [redacted] sets) will be manufactured and the application of the weld overlay and weld defect repair will be further tested and demonstrated.

3. <u>Commissioning</u>
   In this Phase, commissioning tests and available for service declaration will occur, with likely one commissioning trial at a Darlington unit in 2010.

5/ QUALITATIVE FACTORS

Using Weld overlay technology in combination with the Cut & Weld method (as required) potentially offers the following qualitative benefits:

- Eliminates the need for isolating, draining, removal and replacement of feeders experiencing thinning in the area adjacent to the Grayloc hub, thereby reducing production and safety areas of risk inherent in breaking the pressure boundary.
- Reduces exposure time, thereby achieving an overall reduction in radiation dose uptake.
- Reduces both the potential for loose contamination release and the production of high level active waste associated with Cut & Weld activities.

As well, this repair technology may be considered for providing a potential repair technique for pipe thinning problems in other systems or at other OPG stations.

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9			[illegible]
		Impact			
		1	2	3	4	5
Probability	5	5	[illegible]	[illegible]	[illegible]	[illegible]
	4	4	8	[illegible]	[illegible]	[illegible]
	3	3	6	9	[illegible]	[illegible]
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
The vendor's proposed cost of Stage 2 scope (Tool Design and Commissioning) is significantly higher than current estimates. Impact: Higher than estimated capital costs; lower NPV; delay to project resulting from the requirement for a superseding BCS approval.	▪ Conservative estimates based on Cut and Weld tooling development experiences have been used. ▪ A [redacted]% general contingency has been established for this project phase. ▪ A competitive atmosphere for award of Stage II has been set up with two vendors performing Stage I activities. ▪ A firm price contract will be negotiated.	12	15							15	6	8							8
The scope of work may increase based on unresolved technical issues, or discovery of new issues, or Regulatory requirements. Impact: Increased costs, schedule extension and increased complexity	▪ A [redacted]% general contingency has been established for this project phase. ▪ The proof of concept phase disclosed significant technical risks. ▪ Experienced vendors have been contracted.	16	20		8					20	6	15		6					15
The schedule necessary to meet the DNGD 2011 outage may not be achievable resulting in repair of feeders solely with cut and weld tooling during this outage. Impact: An estimated decreased	▪ Experienced vendors are being used. ▪ A competitive atmosphere between vendors has been established to increase their motivation. ▪ Capital funding release is being	20	25							25	16	20							20

Low = 1 to 3		Medium = 4 to 9			
	Impact				
Probability	1	2	3	4	5
5	5				
4	4	8			
3	3	6	9		
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
savings of approximately $10M-$20M (NPV).	sought in order that Stage II award is not delayed.																		
Availability of long lead parts/tools (e.g. feeder mock-up) may delay tool development (Stage 2) and subsequent tool AFS resulting in repair of feeders solely with cut and weld tooling during the 2011 Darlington outage. Impact: An estimated decreased savings of approximately $10M - $20M (NPV).	▪ Plan to include Mock-up in vendor's deliverables for early Stage II. ▪ Use of existing mock-ups if available.	20	25							**25**	16	20							**20**
Lack of experienced OPG support resources for this project may lead to delays in reviews of deliverables or inadequate reviews. Impact: A delay in completion of this project due to schedule delays or due to rework.	▪ Appropriate engineering and project support resources will be identified and recruited to the project. ▪ Interface agreements will be obtained with required resource/interfacing teams. ▪ Managed task contracts will be set-up with external vendor experts.	8	16	12						**16**	6	9	6						**9**
Tool design and miniaturization may not be able to achieve all feeder configurations that will require repair. Impact: A continued need for cut and weld in inaccessible locations.	▪ The configurations with the most feeders to repair have been identified in the technical specification, and are the demonstration configurations in Stage I. ▪ The specification for the area of damage has been reduced	20								**20**	12								**12**

Low = 1 to 3		Medium = 4 to 9		[illegible]	
	Impact				
Probability	1	2	3	4	5
5	5				
4	4	8			
3	3	6	9		
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	by half since the proof of concept, thus reducing the overlay area required. ▪ Vendors will have to disclose known limitations at the end of Stage I so that this may be accounted for in the final economic evaluation before proceeding with Stage II.																		
The "As-Built" clearances at the grayloc area of some feeders may be more restrictive than the designed feeder clearances, resulting in the tooling not being able to fit those Weld Overlay feeder candidates. <u>Impact:</u> The cost of unplanned Cut and Weld repairs; Weld Overlay tool having less value than originally projected.	▪ A sample of actual field measurements will be performed during the spring 2009 DNGS outage to assess the magnitude of the difference. ▪ Actual field measurements of all candidate feeders will be recommended as they are available in lead-up outages to avoid unplanned replacement activities. ▪ Methods will be explored to increase feeder clearances, such as end-fitting jacking techniques.	20		16						20	12		9						12
Post Weld Overlay material properties (Residual Stress, Hydrogen Ingress and Hardness) may not be fully resolved after Stage I. <u>Impact:</u> Schedule delays and cost overrun for additional work	▪ Post Stage I decision meeting to cancel project if risk is too high going into Stage II. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).	15	15							15	6	6							6

Low = 1 to 3		Medium = 4 to 9		[illegible]	
	Impact				
	1	2	3	4	5
Probability 5	5	[illegible]	[illegible]	[illegible]	[illegible]
4	4	8	[illegible]	[illegible]	[illegible]
3	3	6	9	[illegible]	[illegible]
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ Experienced vendors are being used.																		
Weld Overlay repair may not be feasible with fuel in the channel. <u>Impact</u>: Channel will be refueled for the weld overlay repair, increasing time and cost of the repair.	▪ Currently Cut and Weld requires the channel to be defueled therefore the cost of fuel would be the same under both Cut & Weld and Weld Overlay scenarios should this risk materialize. The cost of fuel has not been included in the economic analysis. (If included, the case for Weld Overlay is made stronger).	4								4	2								2
Regulatory approval sought in Stage II may be delayed or rejected. <u>Impact:</u> Schedule delays and cost overrun for additional work required. At worst, cancellation of the weld overlay project would result in sunk costs of approximately $16.5M OM&A (includes contingency) and any Stage II expenditures (Capital Release).	▪ A Regulatory plan has been prepared and an initial meeting held early in the project. ▪ During Stage I, at least one update meeting will be held with the CNSC ▪ Technical experts with knowledge in Code/Regulatory issues will be contracted for this work and will support Regulatory discussions and submissions. ▪ Nuclear Weld Overlay experience from utilities will be	12	15			9				15	6	8			4				8

Low = 1 to 3		Medium = 4 to 9			
	Impact				
Probability	1	2	3	4	5
5	5				
4	4	8			
3	3	6	9		
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	sought. ▪ Removed DNGS feeders (artifacts) have been set aside for weld overlay testing purposes (if required).																		
The Regulator may require a 48 hour wait prior to Ultrasonic Inspection of the overlaid area. This wait may be deemed necessary to allow crack initiation for hydrogen. Impact: The benefits of Weld Overlay will be reduced by the net additional time required for inspection.	▪ Stage I development includes significant effort to determine and minimize hydrogen ingress during weld overlay. Based on successful development in this area, the 48 hour period should not be required. ▪ Industry OPEX of weld overlay will be used to present a case that hydrogen induced cracking is not an issue.	16								**16**	12								**12**
The number of candidate weld overlay feeder repairs is reduced due to the approval of lower pipe thickness limits or adjustments to the rate of thinning calculations. Impact: Less return on investment. At worst, sunk costs could reach *$16.5M* OM&A (Including contingency) and any Stage II expenditures (Capital Release)	▪ Maintain communication with Feeder experts and stakeholders to quickly respond to changes in feeder condition or assessments. ▪ At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II; the minimum thickness limits will be reconfirmed at this time.	15								**15**	10								**10**
There may be a requirement for a Cut and Weld crew on standby as contingency during weld overlay. This standby charge	Supply chain to negotiate if required.	3								**3**	3								**3**

Low = 1 to 3	Medium = 4 to 9				
	Impact				
	1	2	3	4	5
Probability 5	5				
4	4	8			
3	3	6	9		
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Probability x Impact – Before Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	Probability x Impact – After Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
may be significant. Impact: Less return on investment.																			
The efficiency (time required) or the application cost per feeder of weld overlay is greater than that for cut and weld. Impact: Less return on investments. At worst, sunk costs could reach $16.5M OM&A (Including contingency) and any Stage II expenditures (Capital Release)	• At the conclusion of Stage I, the economic benefits will be re-assessed prior to proceeding with Stage II	8								8	8								8
The value of the Canadian dollar drops to a value for a sustained period of time that may significantly increase costs should a vendor from the U.S. be contracted for this job (<$0.8 USD). Impact: Higher cost of development and/or application	• Request proposals in Canadian funds. • 25% contingency has been added to conservative estimates.	12								12	6								6
The vendor's QA program is not approved for stage II work and/or implementation Impact: That vendor's bid is not acceptable.	• OPG Supply chain is engaged in reviewing and auditing the vendor's QA program. • Two vendors are contracted for stage I work.	8	15							15	8	10							10
Opportunity - Another utility with	• Senior Management to									4									8

Low = 1 to 3	Medium = 4 to 9	[illegible]			
	Impact				
Probability	1	2	3	4	5
5	5	10	[illegible]	[illegible]	[illegible]
4	4	8	[illegible]	[illegible]	[illegible]
3	3	6	9	[illegible]	[illegible]
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
similar grayloc thinning issues may join OPG as a partner in the Weld Overlay Project. This would result in reduced weld overlay project costs by a significant amount.	continue discussions with interested utility.	4									8								
Opportunity – Process and tooling may be used for other Stations or systems.	•	9								9	9								9
Opportunity – Introduction of an alternate vendor for feeder repair may lead to more competitive quotes for future work.		6								6	6								6

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Comprehensive	Jun 2011	Dec 2012	VP Science & Technology Development

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Time to perform a single repair	Cut & Weld	<25 hours	Use outage reporting data	Performance Engineering
2.	Dose per repair	Cut & Weld	< cut and weld	mRem/Feeder Dose reporting system.	Reactor Maintenance
3.	Number of feeders that require cut and weld replacement per 100 feeders requiring repair.	Cut & Weld	< 10	Use outage reporting data	Major Components/ Feeders
4.	Weld overlay in-service repair failures.	N/A	0	SCRs	Major Components/ Feeders
5.	Number of pipe 'blow-thru' events	N/A	0	SCRs	Reactor Maintenance
6.	Cost per repair average.	Cut & Weld	< 500k in first 3 years	Negotiated cost per repair	Supply Chain

- A Comprehensive Post Implementation Review (CPIR) will be carried out at the conclusion of Stage 1 of the project to capture the lessons and make recommendations for the next stage. If a CPIR is found not appropriate at the end of Stage 1, it will be conducted within one year of the project in service (by December 2012), consistent with the corporate PIR Procedure.

- The Comprehensive PIR will be an independent and systematic performance evaluation of the project for these objectives:

  - Assess the realization of the project benefits consisting of:

    i. The effectiveness of the weld overlay repair technology in conjunction with Cut & Weld tooling over the previous cut and weld method alone

    ii. The measurement of project targets specified in the table above

- Review project intent, plan, implementation and operational performance
- Review BCS - major assumptions, economic and financial evaluation looking back from results, for future decisions
- Review project risk management
- Identify over all lessons learned, in addition to those documented by the project team, for future improvement

- The Comprehensive PIR will be conducted by Independent Team with the Team Leader appointed by the Project Approval Authority
- Key Lessons-Learned on the technology development, contracting and planning will be captured in addition to the project execution lessons.

Appendix "A" Glossary (acronyms, codes, technical terms)

- Acronyms etc are spelled out in the text.

Appendix "B" Project Funding History

$ 000's Capital Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values							2015	Later	Total
		Year	2009	2010	2011	2012	2013	2014			
Full	May	2009	5,050	45,060	3,084						53,194
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Feb	2009	0								0

$ 000's OM&A Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values							2011	Later	Total
		Year	2005	2006	2007	2008	2009	2010			
Developmental	Feb	2005	200								200
Partial	Jun	2005	1,500								1,500
Partial	Jul	2006	1,273	686							1,959
Partial	Aug	2007	1,273	407	670	3,560					5,910
Partial	Oct	2008	1,273	407	497	3,867	10,490				16,534
Full	May	2009	1,273	407	497	3,867	10,490	1,000			17,534
											0
											0
LTD Spent	Feb	2009	1,273	407	497	1,470	260				3,907

Comments:

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	2%	SR & D Opportunity	Yes
Progress Payments	Yes	Foreign Currency	See Comments	Retainer Fee	No
Income Tax Rate	Generation	PST	See Comments	Interest Rate (Capital)	6%
Depreciation Rate (Capital)	Office, Misc Equipment 20%	Leasing	No	Indexed Priced Contract	No

Comments:

[redacted]% of tool development costs (~$[redacted]M) has been reserved in a specific contingency to cover uncertainties regarding applicability of PST which will not be resolved until the successful completion of Stage I.

Any Stage II foreign exchange issues will be covered by the 25% general contingency requested in this release.

Project Cost Estimate:

Design Complete	Zero to Minimal	Quality of Estimate	Conceptual + 60% to - 25%	3rd Party Estimate	Yes
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	No	First Unit Actual Used	N/A
Cost Sharing	No	Contracts in place	No	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service	No	Firm Vendor Proposal	No

Comments:

Refer to N-REP-30751-10007, "*Economic Analysis to Support Weld Overlay BCS N-BCS-30751-10002*" for detailed financial model assumptions used in the development of this business case.

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A	N/A	N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	Sep	2018	935	88%	D1111	D1411	D1711				
	2	May	2016			D1021	D1321					
	3	Mar	2020			D1231	D1531	D1831				
	4	Mar	2021			D1341	D1641					

Comments:

D1021 is included as target commissioning outage.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Risk Informed Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Base Case	**0.0**	**0.0**	(8.6)	(23.0)	(3.0)	(23.7)	(34.2)	(22.0)	(151.5)	(266.0)
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Recommendation	**0.0**	**0.0**	(8.6)	(10.9)	(1.2)	(11.3)	(18.3)	(12.2)	(83.3)	(145.8)
Net Impact	**0.0**	**0.0**	**0.0**	**12.1**	**1.8**	**12.4**	**15.9**	**9.8**	**68.2**	**120.2**

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Outage OM&A	0.0	0.0	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Base Case	**0.0**	**0.0**	(2.7)	(11.7)	(1.8)	(13.1)	(25.9)	(10.7)	(104.8)	(170.7)
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Outage OM&A	0.0	0.0	(2.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(108)
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	(13.9)
Recommendation	**0.0**	**(12.9)**	(3.7)	(7.4)	(1.3)	(8.6)	(16.0)	(6.9)	(65.2)	(122.0)
Net Impact	**0.0**	(12.9)	(1.0)	**4.3**	**0.5**	**4.5**	**9.9**	**3.8**	**39.6**	**48.7**

Comments:

See NPV Calculations for Details and Summary

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Current Assessment Scenario

Impact on Revenue

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH	58.36	52.98	54.58	54.58	56.23	56.23	57.93	57.93		
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(43.1)	(17.8)	(53.2)	(151.4)	(61.0)	(230.0)	**(573.8)**
Base Case	**0.0**	**0.0**	**(17.3)**	**(43.1)**	**(17.8)**	**(53.2)**	**(151.4)**	**(61.0)**	**(230.0)**	**(573.8)**
Probability	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
Consequence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Risk	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Other	0.0	0.0	(17.3)	(19.0)	(8.9)	(23.1)	(83.0)	(34.2)	(126.4)	(311.9)
Recommendation	**0.0**	**0.0**	**(17.3)**	**(19.0)**	**(8.9)**	**(23.1)**	**(83.0)**	**(34.2)**	**(126.4)**	**(311.9)**
Net Impact	**0.0**	**0.0**	**0.0**	**24.1**	**8.9**	**30.1**	**68.4**	**26.8**	**103.6**	**261.9**

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$Millions	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Outage OM&A	0.0	0.0	(10.6)	(23.5)	(7.4)	(29.1)	(101.5)	(37.1)	(161.6)	**(370.8)**
Project OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Base Case	**0.0**	**0.0**	**(10.6)**	**(23.5)**	**(7.4)**	**(29.1)**	**(101.5)**	**(37.1)**	**(161.6)**	**(370.8)**
Base OM&A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Outage OM&A	0.0	0.0	(10.6)	(14.6)	(4.9)	(17.8)	(62.9)	(23.3)	(101.4)	**(235.5)**
Project OM&A	0.0	(12.9)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	**(13.9)**
Recommendation	**0.0**	**(12.9)**	**(11.6)**	**(14.6)**	**(4.9)**	**(17.8)**	**(62.9)**	**(23.3)**	**(101.4)**	**(249.4)**
Net Impact	**0.0**	**(12.9)**	**(1.0)**	**8.9**	**2.5**	**11.3**	**38.6**	**13.8**	**60.2**	**121.4**

Comments:

See NPV Calculations for Details and Summary

Weld Overlay Project 10 - 62568 Capital 10 - 62435 OM&A

Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "A" **Project Cost Summary**

	$000's OM&A	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)	708	470							1,178
	Engineering & Drafting (OPG)	202	315							517
	Material	[redacted]								
	Contract - Other									
	Interest (Capital Project Only)									-
	Project Costs	[redacted]								
	General Contingency									
	Specific Contingency									
	Project Costs	**3,647**	**12,887**	**1,000**	**-**	**-**	**-**	**-**	**-**	**17,534**
Cash	Adjust to Cash Basis + / -	-	-	-						-
	Project Costs	**3,647**	**12,887**	**1,000**	**-**	**-**	**-**	**-**	**-**	**17,534**
Funding	**Currently Released**	3,647	12,887							16,534
	This Release			1,000						1,000
	Future Release								-	-
	Project Funding	**3,647**	**12,887**	**1,000**	**-**	**-**	**-**	**-**	**-**	**17,534**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	2009-2013 Business Plan	2,893	4,240							7,133
	Variance to Business Plan	**754**	**8,423**	**-**	**-**	**-**	**-**	**-**	**-**	**7,177**

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Other	**Removal Costs Included above**									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

Weld Overlay Project 10 – 62435 OM&A
Full Release Business Case Summary N-BCS- 30751-10001-R000
Project Cost Summary

Attachment "A"

	$000's Capital	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnl & Support									-
	Engineering									-
	Procurement									-
	Construction									-
	Other									-
	Project Management (OPG)		166	507	166					839
	Engineering & Drafting (OPG)		108	108	108					324
	Material		[redacted]							
	Contract - Other		[redacted]							
	Interest (Capital Project Only)		46	1,183	760					1,989
	Project Costs	-	[redacted]							
	General Contingency		[redacted]							
	Specific Contingency		[redacted]							
	Project Costs	-	**5,050**	**45,060**	**3,084**	-	-	-	-	**53,194**
Cash	Adjust to Cash Basis + / -									
	Project Costs	-	**5,050**	**45,060**	**3,084**	-	-	-	-	**53,194**
Funding	**Currently Released**									-
	This Release		4,995	43,905	3,060					51,960
	Future Release								1,234	1,234
	Project Funding	-	**4,995**	**43,905**	**3,060**	-	-	-	**1,234**	**53,194**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	2009-2013 Business Plan		11,000	12,500	1,000					24,500
	Variance to Business Plan	-	**(7,120)**	**21,948**	**1,387**	-	-	-	-	16,215
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By:

Name
Carol Gregoris

April 15/09
Date:

Approved By:

Allan Lew
Eng & Mods Strat IV Manager

15 APR 2009
Date:

Project Name 10 - 62568 Capital 10 - 62435 OM&A

Full Release Business Case Summary N - BCS - 30751 - 10002 – R000

Attachment "B" **Project Variance Analysis**

	Capital & OM&A	LTD Feb 2009	Total Project: Last BCS Oct 2008	Total Project: This BCS Feb 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support				0	
	Engineering				0	
	Procurement				0	
	Construction				0	
	Other				0	
	Project Management (OPG)		2,095	2,017	-78	
	Engineering & Drafting (OPG)		626	841	215	
	Material		[redacted]			Mock-Up. Addt'l feeder samples
	Contract - Other		[redacted]			Addt'l costs for WO design, Qualification and commissioning.
	Interest (Capital Project Only)		1,000	1,989	989	
	Project Costs (Scores Basis)	**0**	**38,810**	**55,025**	**16,215**	
	General Contingency		[redacted]			
	Specific Contingency		[redacted]			PST Applicability, Commisioning
	Project Costs (Scores Basis)	**0**	**47,533**	**70,728**	**23,195**	

Other	Removal Costs Included above	-	-	-	0	
	Inventory to be written off	-	-	-	0	
	Spare Parts in inventory	-	-	-	0	

Comments:

Attachment "C" **Milestones and In Service Declarations**

Key Milestones

Completion Date			Description
Day	Mth	Yr	
30	09	2009	Award Stage II Contract
30	11	2010	Commissioning Complete
30	06	2011	AFS

A Project Execution Plan (PEP) **will be approved by Dec 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%
July	2011	In Service	40,500	100
Dec	2011	Project Closure	200	

Attachment D

Decision Map

1. **Recommendation to CNO**
(Process to follow guidelines of Engineering Decision Making N-Guid-01900-10001; Type 3 Decision)

Purpose: To provide a recommendation of either proceeding with Stage II, or canceling the project based on the technical results of Stage I and an updated economic analysis for Stage II. This recommendation will be documented and presented to the CNO, for acceptance.

Chair/Sponsor: Paul Spekkens, VP Science & Technology Development

Attendees:

(1) CNE *
(2) Darlington Director of Engineering *
(3) At least one other Station Engineering Director * (Contrarian Role)
(4) Senior Manager Plant Design Darlington *
(5) Director Engineering Services *
(6) Manager Feeder Integrity Project
(7) Manager Performance Engineering Darlington
(8) Director Nuclear Finance
(9) Manager Nuclear Finance
(10) Manager Darlington Maintenance
(11) Weld Overlay Team Representatives

Format:

Presentation:

- Project Team to present the results of Stage I and an updated risk table based on these results.
- Project Team to present an assessment of the regulatory risk.
- Project Team/Nuclear Finance to present an updated economic analysis incorporating updated:
  1. Costs (vendor proposal in-hand),
  2. Schedule, and
  3. Assumptions.
     - Feeder repair numbers (based on Spring 2009 inspections)
     - Tool limitations (based on clearances vs. conceptual design)
     - Time to apply repair (estimated)
     - Cost of application (budgetary)
     - Monte Carlo analysis results
  4. Other alternatives considered (including lower minimum thickness requirements)

Discussion:
Open discussion and questions

Decision:
CNE makes the decision. Dissenting opinions are to be noted.

Criteria for a decision to proceed should include the following:

- Revised BCS updated economic analysis continues to have a positive NPV.
- Technical risks low; limited medium technical risks may be accepted.
- Regulatory Risk low.

Minutes:

- Presentations, major discussion items, decision, and dissenting opinions are to be recorded.
- Actions with dates should be captured and A/Rs created as appropriate.
- The Recommendation is to be documented and the revised BCS presented for signature by the CNE.

2. CNO acceptance meeting

- CNO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNE
VP Science & Technology Dev (Project Sponsor)
SVP Darlington (or delegate)
Director Station Engineering, Darlington
VP Nuclear Finance
Manager, Feeder Integrity Projects
Project Manager – Weld Overlay Project
- Any actions should be captured and A/Rs created as appropriate
- CNO to take the recommendation and revised BCS to the COO for approval.

3. COO acceptance meeting

- COO acceptance or rejection of the recommendation is to be documented and the revised BCS presented for signature.
- Attendees: CNO
CNE
VP Science & Technology Dev (Project Sponsor)
SVP Darlington (or delegate)
VP Corporate Investment Planning

4. President Approval of Revised BCS

Attachment "E"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule [illegible]	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges OR Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages OR Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Boiler Primary Side Cleaning, Project No. 38296

Please refer to Tab 9

DNGS Units 1-4 SGs Primary Side Cleaning 16 - 38935

38216

Developmental Release Business Case Summary D-BCS-33110-10008-R001

1/ RECOMMENDATION:

Approval is requested to reduce previously approved funding from $4.7M to $2.1M for this Developmental Release of OM&A to complete Darlington SG (steam generator) Primary Side Cleaning (PSC) process qualification and effectiveness testing by a single new external firm, and for subsequent evaluation of the results.

At Darlington, magnetite has always been leaching out of the feeders and the Primary Heat Transport (PHT) System, and depositing on the inner surface of the SG tubes. This tube fouling results in reduced heat transfer and flow in the primary heat transfer system and therefore an increase in reactor inlet and outlet coolant temperatures. At the current rate of flow reduction, the reactor units are projected to reach their end of full power operation by ~ 2013 and will need to be derated from that point on, with a resultant loss of revenue.

The PSC process, developed by an external firm, was applied to Darlington Unit 1 steam generators during the 2004 outage, but the results were not satisfactory. The PSC performed in D411 did not meet the required performance criteria, the firm has not been able to meet testing schedule, and has not made significant improvements to the process. Thus the proposed purchase order to this firm has been cancelled. This will not prevent use of Competitive Bidding process for Site Execution Phase of the Project.

It is proposed to complete the Qualification and Effectiveness testing of the PSC as developed by a new external firm, which has performed four campaigns at another nuclear company. Only after testing will it be possible to determine if the new improved process best meets the cleaning acceptance criteria for DNGS Steam Generators and then to make an informed decision whether it is justifiable to proceed with the Primary Side Cleaning.

An improved primary side cleaning process is expected to provide coolant flow improvements and thus reduced reactor inlet header temperatures, such that unit derating could be postponed until 2016 or 2017, which is very close to the station re-tube date (2018-2021).

This work may be eligible for a Scientific Research and Experimental Development tax credit of 20% on the 2.1M$.

$000's (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011	2012	Later	Total
Currently Released	N/A								-
Requested Now	Developmental		925	1,125	25				2,075.0
Future Funding Req'd					6,000	[redacted]			
Total Project Costs		-	925	1,125	6,025				
Other Costs						[redacted]			
Ongoing Costs									-
Grand Total		-	925	1,125	6,025	[redacted]			-
Investment Type Sustaining		Class OM&A		(IEV) Impact on Ec Value -18 M$		IRR N/A		Discounted Payback N/A	

Submitted By:

S. Woods
Director, Engineering

26 MAR 2009
Date:

Finance Approval:

R. Leavitt
VP Nuclear Finance

March 31 2009
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Wayne Robbins
SVP - Darlington

2009-04-02
Date:

2/ BACKGROUND & ISSUES

At Darlington, the steam generators have experienced degradation in heat transfer capacity due to the buildup of a magnetite layer on the inner surface of the steam generator tubes. This has resulted in reduced flow in the primary heat transport system and an increase in reactor inlet and outlet coolant temperatures.

The rate of reactor inlet temperature increase is estimated at 0.2 - 0.3 °C per year. At this rate, the reactor inlet temperature of the hottest fuel channels will reach the operating limit of 269.4 °C by 2013, at which point continuous reactor derating will be required.

All Darlington units have exhibited a decreasing trend in primary heat transport flow rate over time, which is estimated at approximately 1% per year. This impacts the rate at which heat can be removed from the fuel, which is also impacted by diametrical creep of the pressure tubes, which increases the diameter of the fuel channel. At this rate of flow reduction, the units are projected to reach the Neutron Over Power limit by ~2013 and will need to be derated from that point on.

In addition, the steam generator tube fouling causes difficulties during eddy current inspection of steam generator tubes, reducing probe service life and introducing the risk of probes sticking in the tubes.

A Primary Side Clean Project (PSC) was developed in 2001 to reduce or remove the magnetite layer on the internal surfaces of the steam generator tubes. A process of abrasive blasting with stainless steel shot previously used at other CANDU stations by an external firm was adopted and qualified for a bounding application pressure of 4 bar. (The original intent was to qualify for 6.5 bar but this was reduced due to concerns related to boiler tube damage.)

Following qualification, this process was applied to Darlington Unit 1 steam generators during the D411 spring outage. Approximately 60% of the steam generator tubes were cleaned (as compared to the target of >90%) and an improvement in coolant flow rate of 2.5% was seen, with an average reactor inlet header temperature reduction of 0.7°C as compared to the target of 1.75 - 2.5°C. Due to the disappointing results associated with reactor inlet header temperature, subsequent cleaning operations on the other units were postponed until refinements in the process could be made. The Qualification and Effectiveness testing that was performed was found to have several shortcomings as described in an independent audit report, hence requiring re-qualification and effectiveness testing.

The Primary Side Cleaning performed in D411 did not meet the performance criteria. The external firm which performed D411 Primary Side Cleaning (PSC) has not performed any further PSC campaign since D411, has not demonstrated significant improvements to the process, and has not been able to meet the schedule requirements. Therefore, the PSC PO to this firm has been cancelled. This will not prevent from using Competitive Bidding process for Site Execution Phase of the Project.

Subsequent to the D411 PSC campaign, another firm developed a PSC process and applied it successfully at another nuclear company. Thus Qualification and Effectiveness testing of a Primary Side Cleaning Process developed by this external firm is proposed, to determine if the new process can meet the cleaning acceptance criteria for DNGS Steam Generator and be able to make an informed decision whether it is justifiable to proceed with the PSC.

An improved PSC process should provide coolant flow improvements and reduced reactor inlet header temperatures so that unit deratings could be postponed until 2016 or 2017, which is very close to the station re-tube date (2018 - 2021).

Prior to proceeding with PSC process Design Modifications and Site execution, it is necessary to determine whether the improved PSC process can meet the required cleanliness acceptance criteria and project objectives, as described below. PSC Project objectives (Critical Success Factors) are:

- To provide a more effective and efficient PSC process that can be completed within the outage window (40 days scheduled as per approved Generation Plan) for this process.
- Achieve > 90% tube clean of all four boilers per unit.
- Achieve > average 1.5 °C reactor inlet header temperature reduction. (Note: Unit 1 was already cleaned 60% and the second time ID cleaning after six years may not be able to reach this target).
- Achieve > 3% flow increase in the heat transport system.

It is proposed to perform Qualification and Effectiveness testing of the Primary Side Cleaning Processes developed by a new external firm. Only after testing will it be possible to determine if this process can meet the cleaning acceptance criteria for DNGS Steam Generator and be able to make an informed decision whether it is justifiable to proceed with the Primary Side Cleaning. Qualification testing will include not only the short radius tubes and long radius tubes, but also intermediate radii tubes in order to be able to perform PSC at varying optimum pressures for different radii tubes, instead of a single most limiting one.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	Status Quo	Alt 1 (Recommended)		Alt 2 Delay	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost				
Revenue	11	1	1	-	-	-	
OM&A	60	2	1	-			
Capital				-			
NPV (after tax)	(32)	(50)	(50)	-			
Impact on Economic Value (IEV)	N/A	(18)	(18)				
IRR%	N/A	N/A					
Discounted Payback (Yrs)	N/A	N/A					

Status Quo - Not Recommended

In the Darlington SGs, deposition of magnetite on the inner tube surfaces causes a decreasing trend in primary heat transport flow rate over time, which is estimated at approximately 1% per year. This will result in reactor inlet temperature of the hottest fuel channels reaching the operating limit of 269.4 °C by 2013, at which point continuous reactor derating will be required. The end effect of not doing primary side cleaning is an increasing loss of revenue.

Alternative 1 - Perform Qualification & Effectiveness Testing - Recommended

It is recommended to Complete Qualification and Effectiveness testing of Primary Side Cleaning Process developed by the external firm. Only after testing will it be possible to determine if this process can meet the cleaning acceptance criteria for DNGS Steam Generators and then make an informed decision whether it is justifiable to proceed with the Primary Side Cleaning. An improved primary side cleaning process could provide coolant flow improvements and reduced reactor inlet header temperatures such that unit derating could be postponed until 2016 or 2017, which is very close to the station re-tube date (2018 - 2021).

Alternative 2 - Delay Project - Not Recommended

Feasible but not advisable, as the possible derating window is approaching in a few years.

Alternative 3 – - Not Recommended

Increased margin to dry-out can be achieved by increasing the Primary Heat Transport pressure set-point. The impacts of this change have not been assessed to determine if there are limitations or subsequent effects on the units that would preclude taking this approach.

Alternative 4 – - Not Recommended

Reduction in Reactor Inlet Header Temperature can be achieved by reducing the secondary side pressure set point in the Steam Generator. The impacts of this change have not been assessed to determine if there are limitations or subsequent effects on the units that would preclude taking this approach.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The scope of Work proposed for the current developmental phase of the project is summarized as below:

(1) Perform Qualification Testing to determine the Optimum bounding parameters for most effective cleaning

The previously used process was adopted and qualified for a bounding application pressure of 4.5 bar based on the minimum radius tubes. (Steam generator tubes form a U-bend within the vessel with the tubes closer to the centre of the tubesheet bent in a tighter radius, which is the most limiting case for primary clean qualification.) It is proposed to perform qualification testing of the intermediate radii tubes as well, allowing higher cleaning pressures and more effective cleaning.

Proposed qualification testing will also include laboratory tests and inspections to ensure steam generator tubes will not be damaged during the actual cleaning operation.

(2) Perform Effectiveness Testing to confirm that Cleaning Effectiveness and Performance Targets Can be Met

Simulated fouling was used in the previous qualification testing, which projected successful performance but yielded significantly worse results when actually implemented in the field. Testing of a pulled tube sample, prior to D411, did not provide any useful data. During the current proposed qualification testing, actual tube samples removed from Darlington steam generators will be used to provide more realistic projections of cleaning effectiveness.

(3) Gather data to finalize the decision on whether to proceed with Primary Side Cleaning at Darlington

The scope of the Primary Side Cleaning Project requires process re-development, modification, and re-qualification to provide a more efficient and effective cleaning process than the one used during the D411 outage. If qualification and effectiveness results favour going forward with primary side cleaning, this will be documented in a Full Release BCS for subsequent approval.

(4) Select the Vendor Capable of Providing the Best Results for Darlington

Only one company was available prior to Unit 1 D411 cleaning execution. Since then, another firm has developed a primary side cleaning process and performed four Primary Side Cleaning campaigns at another Nuclear Company. Current information does not allow a determination of which of the two processes will better meet project goals while minimizing overall cost. Qualification and effectiveness testing results from the new firm, and actual cleaning performance results from D411, will allow determination of the most suitable vendor.

Following is the list of deliverables that will be completed as part of this Developmental Release BCS.
(1) Qualification and Effectiveness Test Plan, Procedures, and Inspection and Test Plans
(2) Tube Samples and Test Materials supply.
(3) Qualification and Effectiveness Testing Execution using Contractor's Test Rig, Equipment and Tooling
(4) Final Reports
(5) Results Evaluation

5/ QUALITATIVE FACTORS

- Determine the optimum Qualification Bounding Parameters for Most Effective Cleaning.
- Confirm that Cleaning Effectiveness and Performance Targets can be met.
- Provide data to finalize the decision on whether to proceed with Primary Side Cleaning at Darlington.
- Provide basis to be able to select the Vendor capable of providing the best results for Darlington.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Qualification and Effectiveness Testing is more demanding than originally estimated.	Exceed budgeted cost. May not be able to complete scope within allocated budget.	Medium	Contingency funding ($[redacted]) has been included in this release.	Low
Scope				
Additional tests may be required.	Cost increase and/or schedule extensions.	Low	Any scope changes will be challenged and if found necessary then scope changes will be entertained, once approvals have been obtained from stakeholders in accordance with the scope change process. Contingency funding ($[redacted]) has been included in this release.	Low
Schedule				
Qualification and Effectiveness Testing not completed on schedule.	Delay in evaluation of PSC process performance.	Medium	Ensure coordination with all supporting work groups.	Low
Delay in procurement of Tube sample material for Qualification and Effectiveness Testing.	Delay in completion of Qualification and Effectiveness Testing.	Medium	The procurement of new tube samples is included in the Contractors scope of work, if sample tubes are not available in time, expediting fees (additional cost) may be required.	Low
Resources				
Insufficient resources to perform testing	Delay in evaluation of PSC process performance	Medium	Resources will be provided by Contractor	Low

Technical				
The Qualification and Effectiveness Testing Rig / process equipment not available.	Unable to perform Qualification and Effectiveness Testing.	**Medium**	Vendor is responsible to provide Qualification and Effectiveness Test rig and process equipment, as per Scope of Work.	**Low**
Unable to ship contaminated PSC Process equipment / pulled tube samples to the external firm (off-site).	Radioactive shipment will be required.	**Medium**	Vendor is responsible to provide Qualification and Effectiveness Test rig and process equipment and shipment of equipment and tube samples.	**Low**
Unable to find facility to perform effectiveness testing on contaminated (radioactive) pulled tubes on a full scale mock-up.	Effectiveness Testing will have to be performed on a reduced scale mock-up.	**Medium**	External Firm has to present Strategy and acceptance criteria to ensure reduced scale mock-up testing will replicate the results of full scale mock-up. OPG will review and accept the disposition.	**Low**
Regulatory				
N/A		**N/A**		**N/A**
Environmental				
N/A				
Health & Safety				
N/A		**N/A**		**N/A**
Investment				
Scientific Research and Experimental Development tax credit on Developmental portion is disallowed.	OPG loses 20% tax credit on 2.1M$	**Low**	Work with tax staff and consultant to ensure that the tax credit is allowed.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release			

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Binding Qualification Pressure (large radius tubes)	4 bar	>4 bar	Qualification Test Pressure gauge	Contractor / Engineer EMD
2.	Binding Qualification Pressure (Intermediate radius tubes)	4 bar	>4 bar	Qualification Test Pressure gauge	Contractor / Engineer EMD
3.	Binding Qualification Pressure (short radius tubes)	4 bar	TBD	Qualification Test Pressure gauge	Contractor / Engineer EMD
4.	Effectiveness of magnetite removal from pulled tube sample	None	TDB	Weighing of the tube sample before and after PSC Effectiveness Test.	Contractor / Engineer EMD
5.	No Damage to the tube at qualified parameters, during PSC Qualification & Effectiveness Testing	No damage to the tube samples	No damage to the tube samples	Visual Inspection and NDT of tube samples	Contractor / Engineer EMD / [redacted]

Appendix "A" Glossary (acronyms, codes, technical terms)

PSC	Primary Side Cleaning
NOP	Neutron Over Power
NDT	Non Destructive Testing
TBD	To Be Determined
BCS	Business Case Summary
ALARA	As Low as Reasonably Achievable
JSA	Job Safety Analysis
ITP	Inspection and Test Plan
PEP	Project Execution Plan
PJB	Pre-Job Briefing

Appendix "B"

Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
Developmental	May	2008		3,505	1,125	25					4,655
Developmental	Feb	2009		925	1,125	25					2,075
											0
											0
											0
											0
											0
											0
LTD Spent				925							925

Comments:

Appendix "C"

Financial Model – Assumptions

Project Cost Assumptions:

Cost based on budgetary quote provided by the external firm selected to do the Primary Side Cleaning qualification testing.

Financial Assumptions:

Project / Station End of Life Assumptions:

Base Case	Unit 1	Unit 2	Unit 3	Unit 4
Date of 1st Derate	2013	2013	2013	2013
Derate %	0.5%	0.5%	0.5%	0.5%
# Years Duration	3	3	3	3
Date of 2nd Derate	2016	2016	2016	2016
Derate %	1.0%	1.0%	1.0%	1.0%
Fluence Limit (EFPH) ***	210,240	210,240	210,240	210,240
# Years Duration	EOL	EOL	EOL	EOL

Project	Unit 1	Unit 2	Unit 3	Unit 4
Outage (Clean Date)	2014	2013	2012	2013
Benefit of Clean (years)	5	5	5	5
Benefit of Clean (%)	3.0%	3.0%	3.0%	3.0%
1st Derate % after Clean	0.5%	0.5%	0.5%	0.5%
Length of Derate (yrs)	3	3	3	3
2nd Derate % after Clean	1.0%	1.0%	1.0%	1.0%
# Years (or to Fluence limit)	EOL	EOL	EOL	EOL

Energy Price / Production Assumptions:

	Unit 1	Unit 2	Unit 3	Unit 4
Net Output per Unit (MW)	878	878	878	878
EFPH Time at YE 2007	119,837	118,873	113,530	110,288
Fluence Limit (EFPH) ***	210,240	210,240	210,240	210,240
Rate / MWH (2009)	$54.58	$54.58	$54.58	$54.58
Inflation / Rate Increase				
Revenue infl (2009 to EOL)	2.0%	2.0%	2.0%	2.0%
Base Cost infl (2009 to EOL)	2.0%	2.0%	2.0%	2.0%

Operating Cost Assumptions:

Per 2008-2012 Business Plan, increasing by 2% pa thereafter.

Other Assumptions:

N/A

DNGS Units 1-4 SGs Primary Side Cleaning 16 - 38935

Developmental Release Business Case Summary D-BCS-33110-10008-R001

Attachment "A" **Project Cost Summary**

$000's Capital & OM&A	LTD Prior Yr 2007	This Release 2008	This Release 2009	This Release 2010	Future Release 2010	Future Release 2011	Future Release 2012	Later	Total
Project Management (OPG)	-	33	92	25					150
Engineering & Drafting (OPG)	-	10	68						78
Material									-
Installation – PWU, BTU		-	-						-
Contract - Design	-								-
Contract - Installation									-
Contract - Other		-	105						105
Future Releases					[redacted]				
Contract Qualif. & Effective. Test		882	660						1,542
Interest (Capital Project Only)									-
Project Costs (excl contingency)	-	925	925	25	[redacted]				
General Contingency		-	200						200
Specific Contingency									-
Project Costs (incl contingency)	-	925	1,125	25	[redacted]				
2008-2012 Business Plan	-	1,600	4,300	[redacted]					
Variance to Business Plan	-	(675)	(3,375)	[redacted]					
MFA			-						-
Inventory Write Off Required			-						-
Spare Parts / Inventory			-						-
Total Release (excl contingency)	-	925	925	25	[redacted]				
Total Release (incl contingency)	-	925	1,125	25	6,000	9,000	20,000	60,300	97,375
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Note: Contract-Other include independent Lab./Reviews and Rental charges for [redacted] Equipment off-site storage.
First Primary Side Cleaning Campaign will start in Spring 2012.

Basis of Estimate

Design Complete	Zero to Minimal		Quality of Estimate	Release + 15% to - 10%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	Yes

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By:

Ricardo Fiorini 9-MAR-2009
Ricardo Fiorini
Project Manager

Date:

Approved By:

Dianne Gaine March 9/09
Dianne Gaine
Eng & Mods Manager (Strat IV)

Date:

DNGS Units 1-4 SGs Primary Side Cleaning 16 - 38935

Developmental Release Business Case Summary D-BCS-33110-10008-R001

Attachment "B" **Project Variance Analysis**

OM&A	LTD Dec 2007	Choose One: Last BCS Jun 2008	Choose One: This BCS Feb 2009	Variance	Comments
Project Management (OPG)		180	150	-30	
Engineering & Drafting (OPG)		120	78	-42	
Material				0	
Installation – PWU, BTU		40	0	-40	
Contract - Design				0	
Contract - Installation				0	
Contract - Other		215	[redacted]		
Previous Releases (OM&A + Cap)				0	Scope Reduction as explained in BCS.
Contract Qualification & Effectiveness Testing		3,600	1,542	-2,058	
Interest (Capital Project Only)				0	
Project Costs (excl contingency)	0	4,155	[redacted]		
General Contingency		500	[redacted]		
Specific Contingency				0	
Project Costs (incl contingency)	0	4,655	2,075	-2,580	
MFA			0	0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	4,655	2,075	-2,580	
Total Release (excl contingency)	0	4,155	[redacted]		
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
28	AUG	2008	Qualification & Effectiveness Testing Contract Award
04	JUL	2009	Qualification and Effectiveness Testing Complete
02	NOV	2009	Final Report Complete
19	DEC	2009	Evaluation of Primary Side Cleaning Processes Complete

A Project Execution Plan (PEP) is not required

Comments:

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

1/ RECOMMENDATION:

We recommend the completion of all detailed engineering work and pre-requisites required to support the PNGS-A Unit 4 Boiler Chemical Clean Project (13-49201), and the execution of the Boiler Chemical Clean process during the 2007 Unit 4 outage (with the option to advance execution to 2006). At this time, we require a **full release of $47.4M** for the project.

A successful Boiler Chemical Cleaning must be completed at Unit 4 to ensure generation revenues are protected by eliminating the requirement for boiler tube plugging and potential unit shutdown due to boiler tube denting. A target period of eight years of operation without tube denting can be expected after completion of boiler cleaning at Unit 4. A regulatory commitment to the CNSC has also been made for chemical cleaning the boilers in Unit 4 (REGC AR# 28026033).

In order to prepare for the planned execution of Unit 4 boiler chemical clean in 2007 (with the option to advance execution to 2006), design deliverables must be expedited to allow all installation and execution documentation and prerequisite modifications to be completed in time to allow the option of performing the 2006 Unit 4 boiler chemical clean. Favourable P541 boiler inspection results will defer Unit 4 boiler chemical clean to 2007 – P741 outage; however, planning must be in place now for the execution option in 2006.

In August 2004, a superseding developmental release (NA44-BCS-36330-00002) was approved to provide funding to complete preliminary engineering and initial detailed engineering work. The superseding developmental release brought the project cumulative release amount to $7.9M ($7.2M excluding contingency). With the initiation of detailed engineering, the project is in a position to request this full funding release.

The Unit 4 Boiler Chemical Clean Project is listed in the proposed 2005-2009 Business Plan at $44.3M. Variances will be managed via the Portfolio Management process in 2005.

$Million OM&A		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	7.9	7.2	Jan-05	Spent Life to Date:	4.2
Requested Now:	Full	47.4	38.9	2005-2009	Appr'd Business Plan (Tot Proj):	44.3
Cumulative Release:	Total to Date	55.3	46.1	2005-2009	Business Plan Variance:	1.8
Total Project Estimate:	+30% to -15%	55.3	46.1	2005	Budget (Current Year)	10.2
Current Year Estimate:	2005	17.4	14.5	2005	Budget Variance (Current Yr)	4.3
Type of Investment:	Regulatory	N/A	N/A	Cumulative Release Remaining:		41.9
NPV: Recommendation vs Delaying		116.0	N/A	Contingency on Remaining Release:		9.2
IRR: Recommendation vs Delaying		N/A	N/A	Contingency % on Remaining Release:		22.0%

Submitted By:
J Coleby 8th March '05.

J. Coleby
Site Vice President, PNGS-A
Date:

Finance Approval:
for D. Hanbidge March 9/05
Vice President - Controller
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

R. Dicerni
Acting President & CEO
Date:

2/ BACKGROUND & ISSUES

Boiler Operations & Maintenance

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate. Although their concentrations are low, typically a total of ~2 ppb, over 20 years of operation the amount transported may be as high as several hundred kilograms. In addition, normal start-up evolutions contribute an estimated 10 – 50 kg per start-up.

PNGS has adopted a boiler chemical cleaning (BCC) practice as part of its Boiler Life Cycle Management Plan to remove these deposits to stop or slow the boiler tube degradation mechanisms, particularly tube denting and under-deposit pitting corrosion. Unit 4 boilers are showing early indications of pitting and tube denting (latest inspections results showed 19 dents / 362 pits in all 12 boilers (31000 tubes) inspected). The degradation is not as advanced as compared to other PNGS-A unit boilers, and the chemical controls in place since the Return to Service of this unit have been excellent. However, empirical data from other units has shown that the phenomenon can advance rapidly once initiated. Data on the rate and exact onset is somewhat limited. It is therefore important to address the boiler tube denting on Unit 4 in a timely fashion.

Prevention of boiler tube denting will minimize boiler tube failure due to stress corrosion cracking and also ensure continued unrestricted access of inspection probes to the boiler tube interiors to demonstrate tube fitness-for-service, and will reduce the requirements for tube plugging due to inaccessibility issues. Minimizing the number of plugged boiler tubes will sustain boiler life and protect station against generation revenue losses. Completion of boiler chemical clean can alleviate the Unit 4 boilers of tube degradation conditions for a target period of eight years.

Regulatory and Life Cycle Management Plan

OPG has a regulatory commitment (CNSC) to complete boiler cleaning at Unit 4 (REGC AR # 28026033). The Pickering 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) specifies the requirement for a Boiler Chemical Clean to be conducted on Unit 4 to ensure sustained life of the asset.

Process Selection & Estimate Development

Two process options are available for Boiler Chemical Cleaning: the Hot Boiler Cleaning (HBC) process or the Electric Power Research Institute/Steam Generator Owners Group (EPRI/SGOG) process. The HBC process is too corrosive to apply to Pickering-A boilers due to the large quantity of deposits to be removed, and the boiler material corrosion limits. Therefore, the EPRI/SGOG process was selected for Unit 4 BCC.

The original $31.5M estimate (2004 Business Plan) was based on a cost-sharing scenario with Unit 3 BCC for common design, prerequisite elements, and materials. With Unit 3 BCC project put on hold, the cost-sharing assumption is no longer valid, and the Unit 4 BCC project will have to fund all current BCC work. Additional analysis/reviews of cost assumptions have also been incorporated into the project estimates since this change.

The subsequent estimate of $54.3M (previously listed under the superceding developmental BCS) was based on the assumption that additional dedicated station resources will be available to the project. Further refinement of the project estimate led to two scenarios (detailed in table below): 2006 execution scenario at total project cost of $43.1M; and 2007 execution scenario with 2006 execution option at total project cost of $46.1M. This BCS submission is based on the 2007 Execution (with 2006 option) scenario, as this is expected to be the actual scenario realized. It must be noted that (towards the end of 2005) should a 2006 execution be deemed necessary, the project budget and Business Plan cashflows must be promptly increased to permit such execution.

Execution Scenarios Cost Estimates

Alt	$M (excluding contingency)	2003	2004	2005	2006	2007	2008	Total
1A	2006 Spring Execution	0.3 Actuals	3.4 Actuals	14.5	23.8	1.0	0	43.1
1	2007 Spring Execution (with 2006 Execution Option)	0.3 Actuals	3.4 Actuals	14.5	5.7	22.2	0	46.1

Past Experience

PNGS-A Unit 1 and Unit 2 boilers were previously cleaned using the EPRI/SGOG process. However, the change control environment in early 1990's was not as stringent as today's standards. The equipment and design registration requirements for Unit 4 BCC is much more rigourous than before, and the new engineering change control environment and pressure boundary program requirements are leading to higher overall project costs than previous EPRI/SGOG boiler chemical cleans.

The equipment used and process time for the HBC method is significantly different from the EPRI/SGOG process that will be used for cleaning Unit 4 boilers. These differences prevented the use of common equipment and processes previously developed, and added on to the cost of designing new equipment and processes that is required for EPRI/SGOG.

Project Cost & Schedule

A peer review performed by Helyar & Associates on the cost estimate based on the single-unit execution scenario resulted in a project total of $62.4M. This is 35% higher than the OPG estimate of $46.1M. Helyar's peer review was obtained by using OPG's cost estimate, scrutinizing and supplementing it with additional conservatisms to yield their value; there was no original estimate performed independently using field data. Through detailed planning and monitoring by the project team, and oversight by line management (Management Steering Committee), and through experience from previous boiler chemical cleaning campaigns, the presented estimate ($46.1M) is deemed to be reasonable for completion of Unit 4 BCC.

Pickering Unit 4 currently has planned outages scheduled for 2005 (Fall) and 2007 (Spring). This is based on the standard two year outage interval. Given prerequisite requirements, the project will not be ready for Boiler Chemical Clean execution in the 2005 outage. The earliest readiness date for execution would be 2006 (Spring). Pickering A operational requirements preclude delaying the planned 2005 (Fall) outage to 2006 (Spring). As a result, the current project schedule is aligned for a planned Unit 4 outage in 2005 (P541) for prerequisite activities, and is targeting for the execution outage in 2007 for boiler chemical cleaning with a 2006 execution option. The option would be invoked if boiler tube inspection results in 2005 indicate a requirement to advance the clean. Design deliverables must be expedited to allow all installation and execution documentation and pre-requisite modifications to be completed in time to allow the option of performing the 2006 Unit 4 boiler chemical clean. Pre-requisite activities include installation of access nozzles to boilers, installation of waste transport piping, modifications to boiler blowdown line, installation of containment penetrations, fabrication and testing of boiler cleaning equipment, transportation and staging of equipment, routing and connection of power supplies, development of procedures, and, training and mobilization of personnel.

It should be noted that pre-BCC and post-BCC flushing work will be completed as part of the separate Unit 4 Boiler Flushing Project.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Stop the Project (NPV -$700M) (Not Recommended)
Fitness for service issue – Stop Project
This alternative is **not** recommended. The regulatory commitment (AR# 28026033) to the CNSC requires the completion of boiler cleaning at Unit 4. Potential boiler degradation/denting caused by crevice deposits will also limit unit operation and affect station assets, forcing a unit shutdown and negatively affecting generation revenues if boiler cleaning is not performed. (Reference Pickering 1-4 Steam Generator Life Cycle Management Plan – NA44-PLAN-33110-10003). A premature unit shutdown scenario causing loss of generation revenues could result. For the purposes of calculating a limiting NPV in this scenario: A premature unit shutdown from 2007 (extremely low probability) until its projected end-of-life of boilers (2017) with no mitigating work to restore/replace boilers would lead to an estimated NPV of approximately -$700M (after tax).

Alternative 1 – Prepare for 2006 Clean but Plan for 2007 Clean (NPV -$29M) (Recommended)
Complete all design & prerequisites, Support 2006 Execution Option & Perform Boiler Clean in 2007
Complete all design packages, documentation, prerequisite modifications, and perform boiler chemical cleaning at Unit 4 during the 2007 outage (P741) with the option to execute in 2006. Boiler chemical cleaning operations have successfully been completed on all PNGS-B units and on PNGS-A Units 1 and 2. Costs have been minimized to permit advancing execution to P641 if P541 inspection results are unfavourable (low probability, but contingency to be maintained), and internal and external resources have been optimized. This scenario also maximizes opportunities for execution readiness. The project cost estimate for this alternative is $55.3M (including contingency). Estimated NPV = - $28.7M (after tax).

Alternative 1A – Execute Boiler Chemical Clean in 2006 (NPV -$33M) (Not Recommended)
Move 2007 and all subsequent outages forward by one year.
This alternative is **not** recommended. From a Business Planning perspective, project cost deferral to future years will permit better station cost management since more nuclear generation revenues are expected to be available with more nuclear units online in the near future. Executing BCC (and other major planned U4 outage work) in 2006 will impose a heavy cost load on the station, and subsequent advancing of future planned outages will also shift the cost load towards years with less generation revenues. The project cost estimate for this alternative is $51.7M (including contingency). This alternative should only be selected in the situation where boiler inspection results in 2005 strictly require the earliest execution of U4 BCC.

Alternative 2 - Delay the Recommendation (NPV -$144M) (Not Recommended)
No 2006 Preparation – 2005 inspection indicates Fitness for Service issue – Shutdown Nov 05 to Mar 07
This alternative is **not** recommended. Risk due to denting uncertainty makes this a less prudent option. Upcoming inspection results from P541 may indicate requirement for an earlier boiler chemical cleaning in 2006. If P541 inspection results indicate so, not having the 2006 execution option available will require unit shutdown post-P541 outage due to fitness for service consideration until after completion of U4 BCC in 2007 (though all efforts would be applied to further advance execution readiness should this scenario arise). Loss of generation revenues associated with this forced unit shutdown justifies maintaining the provision for the 2006 execution option.

Alternative 3 - Do Less (Not Recommended)
This alternative is **not** recommended. Chemical Cleaning all twelve Unit 4 boilers is required to satisfy CNSC REGC commitment and to maintain station assets and generation revenues. Costs have been minimized for the current project scope of Unit 4 boiler chemical clean.

Alternative 4 - Do More (Not Recommended)
This alternative is **not** recommended. The selected EPRI/SGOG process has been proven to effectively clean the PNGS-A boiler internals, while maintaining the corrosion levels within acceptable limits. This process has been optimized to provide the degree of boiler cleaning required.

4/ THE PROPOSAL

This full release BCS will allow the completion of the following deliverables.

- Project Execution Plan (R1)
- Detailed Engineering for site modifications and process design packages.
  Packages include:
  - Station Tie-ins
  - RAB/TAB Utilities
  - RB Utilities
  - Containment Inserts
  - BCC System
- Purchase of materials for site modifications and vendor processes
- Development of all vendor and station documentation to support BCC
- Installation of site modifications to support BCC
- Testing and commissioning of process systems
- Execution of Unit 4 BCC
- Demobilization and waste disposal

Milestones Finish Date (D/M/Y)	Description
28-Feb-05	Preliminary Engineering Complete
25-Mar-05	Project Execution Plan (R1) Issued
25-Mar-05	Full Release BCS Approved
29-Mar-05	P541 Workplans Issued
31-May-05	Detailed Engineering Complete
1-Dec-05	P541 BCC Prerequisite Outage Activities Complete
31-Jan-06	P641/P741 BCC Go/No-Go Decision (Tentative)
15-Jun-06	P641 BCC Execution Complete (if 2006 execution option is selected)
15-May-07	P741 BCC Execution Complete
31-Dec-07	Project Close-out

5/ QUALITATIVE FACTORS

Boiler cleaning can result in the following benefits for the station:

- Prevention of further boiler tube denting which will
  - allow more comprehensive and efficient boiler inspections and hence shorter outage time
  - reduce boiler tube plugging requirements and hence lower probability of reactor derating and generation revenue loss or full shutdown
  - stop potential for tube cracking and hence prevent forced outages
- Prevention of corrosion-induced boiler tube leaks which will
  - reduce potential for forced outages
  - reduce potential for environmental releases

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Vendor contract to be time and materials type	Unlike a fixed-price contract, time and materials contract may result in cost escalations. Project could require additional funding.	**Medium**	Clearly define scope of work and introduce incentive / penalty clauses into contract. Detailed monitoring of field activities progress during execution. Allocation of a 20% contingency to project for unforeseen developments.	**Low**
Delays during outage execution (Also affects negatively execution schedule)	Staging of equipment and mobilization of execution resources will have to be extended. Delays may result in outage extension (day-for-day cost increase) and associated generation loss.	**Medium**	Plan in detail execution tasks and logics with Outage Department. Integrate with station Outage Operations and Maintenance departments for optimization of execution. Allocation of a 20% contingency to project for unforeseen developments. Using Framatome with their extensive world wide experience in the BCC area and OPG internal OPEX. Project managed to meet Outage Milestones (Materials/Plans/etc).	**Low**
Early Boiler Chemical Clean may be required based on P541 boiler inspections (advanced rate of denting).	Unit may require to be shut down following P541 or have a short operating period in 2006 prior to Boiler Chemical Clean. Late changes to Project Budget and Business Plan cashflows would be required, and large business plan variances may result.	**Low**	May require access to project contingency, CNO contingency, or re-balance of portfolio to support 2006 Boiler Chemical Clean execution.	**Low**
Scope				
Design and execution scope increase	Increased scope affects project cost and schedule.	**Medium**	Continue review with vendor design group and station stakeholders to define design and execution scope. Strict scope control processes implemented. Management Steering Committee oversight in place.	**Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Schedule				
Further schedule changes to project plan	Insufficient time and resources to accommodate late changes to project plan.	**Low**	Current project direction is for a 2006 boiler chemical clean execution, with prerequisite work to be performed during P541 or before start of P641. (Business Plan is indicating 2007 execution, with 2006 execution as option). Management Steering Committee oversight in place.	**Low**
Permitry issues during BCC execution	Delays to execution window. Need for re-application of permits. This may result in outage extension and associated generation loss.	**Medium**	Involve station Operations early during work planning stages/workplan preparations. Secure stakeholder support on schedule via Task Identification Sheets (TIS) and/or Interface Agreements.	**Low**
Delays during outage execution	See "Cost" category above.	**Medium**	See "Cost" category above.	**Low**
Resources				
Insufficient Project Engineering resources to support BCC. Expertise/experience lost through staff departure.	Backlog of project-related deliverables.	**Medium**	Continue to arrange for contract resources to augment regular staff, and seek knowledgable contractors with previous boiler cleaning experience. May result in delay in project development, but will not result in execution failure. Potential cost impacts/outage extensions are covered by the 20% contingency (see "Cost" above).	**Med to Low**
Limited station resources	Insufficient resources to support BCC execution. This may result in outage extension and associated generation loss.	**Medium**	Secure stakeholder resource support (Operations, Maintenance, Radiation Protection, etc.) via detailed planning and use of Task Identification Sheets and/or Interface Agreements. Reduce station resource reliance by optimizing station interface designs and by extending scope of contract execution support. Ensure continued oversight by Management Steering Committee (PNGS-A Site VP and vendor management as members). May result in delay in project development, but will not result in execution failure. Potential cost impacts/outage extensions are covered by the 20% contingency (see "Cost" above).	**Med to Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Technical				
Insufficient information on boiler nozzle interference to finalize design	Delays in issuance of design packages.	**Medium**	Arrange for boiler nozzle inspections during P541 and complete design packages based on inspection results.	**Low**
Chemical addition strategy	Incorrect concentration of chemicals may affect boiler internals during BCC.	**Low**	Qualification tests to be completed for EPRI/SGOG process prior to execution of BCC.	**Low**
Corrosion Monitoring System (CMS)	CMS functionally inadequate for BCC.	**Low**	CMS to be refurbished to support BCC with required level of functionality and reliability.	**Low**
Regulatory				
CNSC may not formally approve plan for deferred execution of BCC following 2005 Inspection results.	Need to alter plan to execute boiler chemical clean	**Low**	Sought and received initial CNSC concurrence on deferred execution of BCC. Actual BCC execution date to be determined by 2005 inspection results.	**Low**
Environmental				
Air and/or liquid emissions during boiler chemical clean beyond Certificate of Approval limits.	Unplanned release to the environment	**Low**	Continued monitoring of air emissions and liquid wastes generated during boiler chemical clean with reference to Certificate of Approval permitted levels.	**Low**
Metallic deposits removed (in solution form) cannot be disposed of.	Liquid waste remains in waste tankers during execution.	**Low**	BCC waste handling is an integral part of the project, and is being reviewed in detail during engineering design, and will be managed with continued project team oversight during BCC execution.	**Low**
Health & Safety				
Unsafe work practices during vendor execution of BCC. Potential chemical hazards associated with BCC solvents.	Event-Free Day resets / Injuries	**Low**	Oversight by Contract Administrators, Contract Monitors, and Contract Management Team to be emphasized during execution. OPG Contract Management processes implemented. JHSC to be involved early in process development.	**Low**

Description of Risk *(this release only!!!!!)*	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Investment				
Boiler Chemical Clean process does not remove boiler tube/crevice deposits as planned.	Boiler denting problems not remediated	**Low**	EPRI/SGOG BCC process was successfully applied to PNGS-A boilers in Units 1 and 2. EPRI/SGOG is a proven method of boiler chemcial cleaning. All refinements to the process for Unit 4 application will be pre-qualified.	**Low**
Boiler Chemical Clean process causes excess corrosion to boiler internals	Boiler life-cycle negatively affected.	**Low**	Selected EPRI/SGOG process has proven to cause acceptably low level of corrosion during boiler chemical cleaning. Corrosion monitoring system will be in place. Corrosion coupons will also be used to measure corrosion during execution of BCC.	**Low**

As part of the ongoing cost-saving measures, three options as part of detailed design have been identified for review. These options include continuing with detailed design with new BCC equipment (current design direction), relaxing the ECC rigour for detailed design, and pursuing detailed design using existing vendor equipment.
In order to allow the risks listed in the above table to remain comprehensive for the project, the details and specific risks associated with the cost-saving options are listed only in the reference documents below to maintain the clarity of this BCS document.

References:

1. Correspondence, G. MacDonald to J. Marczak, "FANP Assessment of Options for P4BCC", February 24, 2005.
2. Memorandum to File, "PNGS-A Unit 4 Boiler Chemical Clean Project – Risks Associated with Project Cost Savings Options", February 28, 2005.

7/ POST IMPLEMENTATION REVIEW PLAN

The Post Implementation Review (PIR) will be performed in accordance with the PIR Procedure (FIN-PROC-PA-012) and the Simplified PIR Template (FIN-TMP-PA-002). Design Projects, in cooperation with Finance, Engineering Mechanics & Codes Department; Chemistry, Metallurgy & Welding Department, will perform the PIR with a target completion date of December 2007. The results of the project will be documented and compared against the following baseline criteria (in development). Major lessons-learned from the project will be documented in a report. In addition, the boiler performance will continue to be monitored under the Pickering Unit 1-4 Steam Generator Life Cycle Management Plan.

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**May 2007**	**Dec 2007**	**Manager, Components & Equipment, PNGS-A**

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Corrosion during BCC	N/A	Within corrosion limits (limits to be finalized in NA44-REP-36330-00001: EPRI/SGOG Chemical Cleaning Process for Pickering-A)	Via Corrosion Monitoring System (CMS) and corrosion probes & coupons.	CM&W Dept. & Engineering Mechanics Dept.
2.	Deposit removal	N/A	6500 - 8500 kg	Via Waste Solvent calculations.	CM&W Dept.
3.	REGC AR 28026033	N/A	Fulfillment of commitment	Via successful completion of BCC during outage.	Components & Equipment, PNGS-A.
4.	[Qualitative] Removal of Crevice Deposits	N/A	Crevices cleaned	Post BCC inspection results to be reviewed	CM&W Dept.
5.	[Qualitative] Reduction in Boiler Tube denting	N/A	Based on crevice deposit removal	Post BCC inspection results to be extrapolated	Engineering Mechanics Dept.
6.	[Qualitative] Reduction in corrosion induced boiler tube leaks	N/A	Consistent with Life Cycle Management Plan expected performance	Post BCC inspection results to be extrapolated	Engineering Mechanics Dept.

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,880	1,400	1,870		**5,667**	635	**11.2%**
Engineering & Drafting (OPG)	169	649	1,380	620	660		**3,478**	863	**24.8%**
Material		2	300	100	300		**702**	2	**0.3%**
Installation – PWU, BTU		91	1,300	900	3,210		**5,501**	118	**2.1%**
Contract – Project Mgmt		-	-	-	-		**-**		
Contract - Design		2,238	2,600	200	200		**5,238**	2,583	**49.3%**
Contract - Installation			6,000	1,500	13,000		**20,500**		
Contract - Other			1,000	1,000	3,000		**5,000**		
							-		
							-		
							-		
							-		
							-		
							-		
							-		
Interest (Capital Project Only)							**-**		
Sub Total (excl Contingency)	**275**	**3,391**	**14,460**	**5,720**	**22,240**	**-**	**46,086**	**4,201**	**9.1%**
Contingency	-	-	2,890	1,140	5,190	-	**9,220**	**N/A**	**N/A**
Grand Total	**275**	**3,391**	**17,350**	**6,860**	**27,430**	**-**	**55,306**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	**44,253**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	**-**	**(1,281)**	**4,280**	**320**	**(510)**	**(976)**	**1,833**	**N/A**	**N/A**

Table A: Cashflows and Breakdowns for Alternative 1 (Execution of U4 BCC in 2007 with 2006 Option).

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: John Marczak 2005-Mar-08
Date:
J. Marczak
Project Manager

Approved By: P.L. Floyd March 8/05
Date:
P. Floyd
Eng & Mods Manager (Strat IV)

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44 -BCS-36330-00003-R000

Attachment "B" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,880	1,880	650		**4,927**	635	**12.9%**
Engineering & Drafting (OPG)	169	649	1,400	700	140		**3,058**	863	**28.2%**
Material		2	300	300	-		**602**	2	**0.3%**
Installation – PWU, BTU		91	1,350	3,030	280		**4,751**	118	**2.5%**
Contract – Project Mgmt		-	-	-	-		**-**		
Contract - Design		2,238	2,600	400	-		**5,238**	2,583	**49.3%**
Contract - Installation		-	6,000	14,000	-		**20,000**		
Contract - Other		-	1,000	3,500	-		**4,500**		
Interest (Capital Project Only)							**-**		
Sub Total (excl Contingency)	**275**	**3,391**	**14,530**	**23,810**	**1,070**	**-**	**43,076**	**4,201**	**9.8%**
Contingency	-	-	2,900	5,500	215		**8,615**	**N/A**	**N/A**
Grand Total	**275**	**3,391**	**17,430**	**29,310**	**1,285**	**-**	**51,691**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	**44,253**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	**-**	**(1,281)**	**4,350**	**18,410**	**(21,680)**	**(976)**	**(1,177)**	**N/A**	**N/A**

Table B: Cashflows and Breakdowns for Alternative 1A (Execution of U4 BCC in 2006).

Comparing against cost details of Alternative 1 (Attachment A), the following can be noted.

- Overall higher cost (mainly in Project Engineering and Installation) for Alternative 1 is associated with the need for:
  - Re-work of documentation (execution workplans, process procedures, etc.),
  - Re-training of execution crews & Re-mobilization,
  - Re-scheduling of execution activities for Outage schedule alignment.
  - Maintenance of resource readiness.

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: J. Marczak 2005-Mar-08
Date:
J. Marczak
Project Manager

Approved By: P. L. F. Floyd March 8/05
Date:
P. Floyd
Eng & Mods Manager (Strat IV)

PNGS-A Unit 4 Boiler Chemical Clean 13 - 49201

Full Release Business Case Summary NA44-BCS-36330-00003-R000

Attachment "C" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2003	LTD Prior Years 2004	2005	2006	2007	2008	Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	106	411	1,320	1,960	1,870	-	**5,667**	635	**11.2%**
Engineering & Drafting (OPG)	169	649	970	1,030	660	-	**3,478**	863	**24.8%**
Material		2	210	200	300	-	**712**	2	**0.3%**
Installation – PWU, BTU		91	910	1,300	3,210	-	**5,511**	118	**2.1%**
Contract – Project Mgmt		-	-	-	-		**-**		
Contract - Design		2,238	1,820	980	200		**5,238**	2,583	**49.3%**
Contract - Installation		-	4,200	3,300	13,000	-	**20,500**	-	**0.0%**
Contract - Other		-	700	1,300	3,000		**5,000**		
							-		
							-		
							-		
							-		
							-		
							-		
							-		
Interest (Capital Project Only)							**-**		
Sub Total (excl Contingency)	**275**	**3,391**	**10,130**	**10,070**	**22,240**	**-**	**46,106**	**4,201**	**9.1%**
Contingency	-	-	2,025	2,015	5,180		**9,220**	**N/A**	**N/A**
Grand Total	**275**	**3,391**	**12,155**	**12,085**	**27,420**	**-**	**55,326**	**N/A**	**N/A**
2005-2009 Business Plan	275	4,672	10,180	5,400	22,750	976	**44,253**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	**-**	**(1,281)**	**(50)**	**4,670**	**(510)**	**(976)**	**1,853**	**N/A**	**N/A**

Table C: Alt # 2 (Execution of U4 BCC in 2007 with Unit Shutdown from November 05 to March 2007).

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Budget Estimate +30% to -15%**
Design Complete:	**Up to ~ 40%**

Reviewed By: John Marczak 2005-Mar-08
Date:
J. Marczak
Project Manager

Approved By: P.M. Floyd March 8/05
Date:
P. Floyd
Eng & Mods Manager (Strat IV)

U4 Boiler Flushing - Project# 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

1/ RECOMMENDATION:

We recommend additional release of $13.1M ($11.2M plus $1.9M contingency) for a project total of $14.7M ($12.8M plus $1.9M contingency) to secure the funding required to 1) complete development of the Boiler Flushing process, 2) execute the field pre-requisites (i.e. boiler nozzle installations, shroud hole repairs, and mechanical and electrical modifications) in P541 to support and equip for the Flushing and Boiler Chemical Clean (BCC) programs, and 3) execute the pre-BCC and post-BCC flushing in the P741 outage.

There is a possibility, as a result of the P541 boiler inspections, that the BCC and Flushing activities may be required prior to P741; therefore, the Flushing program must be planned and ready for execution in 2006 (P641).

The business objective of this project is: 1) to prevent the boiler tube degradation by removing the unhardened sludge deposits collected on top of the tube-sheet, and 2) support the BCC project (13-49201), which is to ensure generation revenues are protected by eliminating the requirement for boiler tube plugging and potential unit shutdown due to boiler tube denting. There is a regulatory commitment to the CNSC for chemical cleaning of the 12 boilers in Unit 4 (REGC AR # 28026033).

A previous developmental release of $1.6M was made under NA44-PLAN-36340-00001, of which $660k has already been spent to complete the preliminary engineering and start the detailed engineering on both the site modifications and the flushing process. More specifically, the preliminary design and the detailed engineering for the site modifications have been completed, while preliminary engineering has been completed and the development of the flushing process is being started. Consequently after the change in requirement to execute Flushing in the same outage as BCC, as evident through preliminary engineering (as per the scope in NA44-PLAN-33110-00004), the Flushing related activities were deferred from the 2004 schedule; this resulted in considerably less funds spent in 2004 than was budgeted.

This project is listed in the 2005-2009 approved business plan with a project total of $14.5M ($1340k was budgeted for 2004). See attachment "A" for details. Any cash flow variances to this Plan will be addressed through the Portfolio Management Process. Currently the BCC is under review, and will be presented to the Board of Directors in March 2005. If the BCC is not approved, a superceding release will be processed to reduce the amount of this project accordingly.

Choose One		Including Contingency	Excluding Contingency			Excluding Contingency
Released to Date:	Developmental	1,600	1,600	Jan-05	Spent Life to Date:	660
Requested Now:	Full	13,100	11,200	2005-2009	Appr'd Business Plan (Tot Proj):	15,820
Cumulative Release:	Total to Date	14,700	12,800	2005-2009	Business Plan Variance:	(3,020)
Total Project Estimate:	+30% to -15%	14,700	12,800	2005	Budget (Current Year)	5,000
Current Year Estimate:	2005	5,765	4,995	2005	Budget Variance (Current Yr)	(5)
Type of Investment:	Regulatory	N/A	N/A	Cumulative Release Remaining:		12,140
NPV:			N/A	Contingency on Remaining Release:		1,900
IRR:			N/A	Contingency % on Remaining Release:		15.7%

Submitted By: John Coleby. 26 Feb 2005

J. Coleby
Vice-President, PNGS-A

Date:

Finance Approval: D. Hanbidge

for D. Hanbidge
Vice-President, Controller, OPG

March 2/05
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Mar 7/05

P. Charlebois
Chief Nuclear Officer

Date:

2/ BACKGROUND & ISSUES

Boiler Operations & Maintenance

During normal, steady state operation of nuclear power plants, small amounts of metallic impurities, principally iron, nickel, zinc and copper, are transported via the feedwater to the secondary side of the boilers where they slowly accumulate. Although their concentrations are low, typically a total of ~2 ppb, over 20 years of operation the amount transported may be as much as several hundred kilograms. In addition, normal start-up evolutions contribute an estimated 10 – 50 kg per start-up.

PNGS has adopted a boiler chemical cleaning (BCC) practice, as part of its Boiler Life Cycle Management Plan, to remove these deposits and stop or delay the boiler tube degradation mechanisms, particularly tube denting and under-deposit pitting corrosion. The Unit 4 boilers are showing early indications of pitting and tube denting (recent inspections showed 19 dents / 362 pits in all of the 12 boilers (31000 tubes) inspected). In comparison to the other PNGS-A unit boiler, the degradation is not as advanced, as the chemical controls in place since the Return to Service of this unit have been excellent. However, empirical data from other units have also shown that degradation can advance rapidly once initiated (data on the rate and exact onset is somewhat limited). It is therefore important to address the boiler tube denting on Unit 4 in a timely fashion.

Prevention of boiler tube denting will minimize boiler tube failure due to stress corrosion cracking, and ensure continued unrestricted access of inspection probes to the boiler tube interiors for tube fitness-for-service evaluations. It will also reduce the requirements for tube plugging due to inaccessibility issues. Furthermore, minimizing the number of plugged boiler tubes will sustain boiler life and protect the station against generation revenue losses. The completion of boiler chemical clean can alleviate the tube degradation conditions of the Unit 4 boilers for a period of eight years.

Regulatory and Life Cycle Management Plan

Flushing activities are required as on going "maintenance" activities as per the Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) to control the secondary side deposits.

OPG also has a regulatory commitment to the CNSC to complete boiler cleaning of Unit 4 (REGC AR # 28026033). The Pickering Unit 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003) and the Pickering Unit 4 – 2005 Steam Generator Outage Scope Plan (NA44-PLAN-33110-00004) specify the requirement for a Boiler Chemical Clean to be conducted on Unit 4 to ensure sustained life of the asset. To fulfill this requirement, boiler flushing must be performed prior to and after BCC. The Pre-Flush will remove the build up of "soft" deposits to expose the "hard" pile to the BCC process, while the Post-Flush will remove the deposits dislodged or "softened" by the BCC process.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

Do Nothing (Not Recommended)

This is **not** recommended. OPG has a regulatory commitment to the CNSC to complete boiler cleaning of the Unit 4 boilers (REGC AR # 28026033). Pickering Unit 1-4 Steam Generator Life Cycle Management Plan (NA44-PLAN-33110-10003 R0) outlines the need for the boiler flushing process in relation with BCC operations as well as to control the secondary side deposits. The nozzles installed under this project are required for BCC execution. Boiler tube fouling/denting will limit unit operation if BCC and Flushing operations are not performed.

Alternative 1 – Execute Boiler Pre-req's in P541 and perform Flushing in P741 (Recommended)

Execute the BCC and Flushing prerequisites (i.e. install boiler nozzles, repair shroud holes, and complete electrical and mechanical modifications) during the P541 outage in parallel with other boiler work. Develop a flushing process and execute the pre- and post- BCC flushing during the P741 outage. This approach is recommended. There is a possibility that execution of Flushing and BCC may be required prior to the scheduled P741 outage; thus, flushing developments need to be done early to accommodate a P641 outage.

Alternative 2 - Delay the Recommendation (Not Recommended)

2.1. Delay the prerequisites execution.

This is not recommended. The execution of prerequisites (i.e. nozzle installation, shroud repair and electrical and mechanical modifications) can be done during P541 in parallel with the Feedwater Nozzle Thermal Sleeve Replacement (TSR), and should have no impact on the P541 outage duration. If the boiler prerequisites are not executed in the P541 outage, and delayed until the next outage (P741), this activity will become a "series" activity with the Flushing and BCC activities and will increase the length of the outage by approximately 25 days.

2.2. Delay the Flushing development closer to the P741 outage.

This is not recommended, as there is the possibility that BCC and Flushing activities may be advanced to a P641 outage.

Alternative 3 - Do Less (Not Recommended)

3.1. Execute a pre-BCC Flush only or a post-BCC only.

This is not recommended. A post-BCC flush is required to remove the solid deposits from the boiler dislodged by the BCC process. If Flushing is not done prior to BCC to remove the build up of "soft" deposits to expose the "hard" pile, the BCC process will not be effective.

3.2 Execute Flushing activities only. (If BCC is not approved)

Although this will help address the secondary deposit issue, this will not fully address the requirements set out in the Life Cycle Management Plan – nor fulfill the REGC shown above.

Alternative 4 - Do More (Not Recommended)

4.1. Progress the development of the Flushing process and execute the Flush during P541 prior to P741 .

This is not recommended. Flushing must be performed in the same outage as BCC to remove "soft" deposits and expose the "hard" deposits for maximum benefits of BCC.

4.2. Execute a Flush in both P541 and P741

This is not required by the Boiler Life Cycle Management Plan and would significantly increase the duration of the P541 outage.

Alternative 5 – Other - N/A

4/ THE PROPOSAL

The additional release of $13.1M (11.2M + 1.9M contingency) will be used to complete the development of the Flushing process, award contracts with Vendor(s) to prepare and execute the boiler pre-requisites, and execute the pre- and post- BCC flushing activities. The project cost estimate is based on estimates received from vendors, and past and current flushing activities being performed on Pickering B boilers. The total project cost was also evaluated by a third party (Helyar); their estimate including contingency is approximately 30% higher. The difference is largely due to the third party's use of "conceptual quality" information and a higher amount for contingency.

The scope of work addressed with this release:

- project management support
- complete engineering activities
- finalize contracts with vendor(s)
- pre-mobilization activities (i.e. tooling, mock-ups, training, materials)
- develop an enhanced flushing process for PNGS-A boilers and sludge pile specific configuration
- work plans and ITP's preparation
- assessing activities
- QA and QS activities
- station support (i.e. maintenance, operation, radiation protection)
- contract management support
- permanent power supply installation (for Flushing equipment)
- prerequisites execution - P541 nozzle installation, shroud repair, and electrical & mechanical modifications
- flushing equipment maintenance, testing, preparation for storage
- scaffolding execution (for both the pre-req outage and the Flush/BCC outage)
- execution coordination support (for both the pre-req outage and the Flush/BCC outage)
- pre-BCC and post-BCC Flushing execution (for Flush/BCC outage)
- project / ECC closeout activities

Milestones Finish Date (D/M/Y)	Description
25-Feb-05	Approve Full Release BCS
29-Jan-05	Complete Detailed Engineering for P541 Pre-req Scope
31-May-05	Complete Detailed Engineering for P741 Flushing Scope (aiming to be ready for P641)
29-Mar-05	Finalize Contracts with Vendor(s) for P541 Pre-req Scope
30-Sep-05	Finalize Contracts with Vendor(s) for P741 (aiming to be ready for P641)
29-Mar-05	Issue P541 Workplans
30-Sep-05	Complete enhanced Flushing Development
30-Sep-05	Issue P741 Workplans (aiming to be ready for P641)
1-Dec-05	Complete P541 Flushing Prerequisite activities
3-Jul-07	Complete Pre and Post BCC Flushing activities
30-Dec-07	Complete Project Close-out activities

5/ QUALITATIVE FACTORS

Performing boiler flushing activities result in a more effective BCC. The combination of Flushing and BCC operations can result in the following benefits for the station:

- Prevention of further boiler tube denting which will
  - allow more comprehensive and efficient boiler inspections, and hence decrease outage time
  - reduce boiler tube plugging and hence lower the probability of reactor derating, generation revenue loss or full shutdown
  - minimize the potential of tube cracking and hence prevent forced outages
- Prevention of corrosion-induced boiler tube leaks which will
  - reduce the chances of forced outages
  - reduce the potential of environmental releases

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Higher than estimated vendor(s) cost for the preparation and execution of the P541 outage work.	Overall cost of the project may be greater than estimated.	**Medium**	-Project management has entered into negotiations with vendor and has received proposals from vendor for this work. -Fixed price contract where appropriate to minimize unexpected price increase. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -A portion of the contingency is allocated for this.	**Low**
Enhanced flushing execution may take longer than previous Pickering B flushing job, thereby increasing vendor(s) cost for the preparations and execution of the P741 outage work.	Overall cost of the project may be greater than estimated.	**Medium**	-Project management has entered into negotiations with vendor. The vendor will be requested to follow the outage schedule. -Extensive testing and qualification of the enhanced flushing lance in progress to meet OPG technical specification requirements. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -A portion of the contingency is allocated for this.	**Low**
Scaffold cost greater than estimated.	Overall cost of the project may exceed the estimate detailed in this BCS.	**Medium**	-Project management to work closely with scaffolding vendor to outline requirements and scope. Preliminary estimate from vendor has been received. -Work with other groups to review work plans to mitigate and avoid re-work. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -a portion of the contingency is allocated for this.	**Low**
Scope				
Changes in BCC requirements to increase the scope of boiler pre-requisite work.	Increase in cost and schedule.	**Low**	-Great efforts in the design phase of the BCC project has been made to minimize this threat.	**Low**

Schedule				
Vendor unable to finish execution work along outage schedule.	Increase in project execution duration leading to greater costs.	**High**	-Project Management to involve vendor with schedule development and outage logic, to allow for work to proceed on more than one boiler at a time. Proposals are to include tooling, training, and vendor execution resources. -Maintain close communication between Outage, Projects and Vendor. -Contract administration and monitors are to be assigned to ensure efficient use of resources. -a portion of the contingency is allocated for this.	**Low**
Outage schedule may impact on execution of Boiler Flushing and pre-requiste activities.	Delay in project execution duration leading to greater costs.	**Medium**	-Maintain close communication between Outage, Projects and Vendor -P541 outage scope was frozen on Dec. 15, 2004.	**Low**
Advancement in Boilier Flushing and BCC work if P541 inspections deem necessary.	Execution schedule advanced to P641.	**Medium**	-Prepare workplans and develop enhanced flushing process early to accommodate for a P641 outage.	**Low**
Resources				
Insufficient Contract Administration support.	Delay in schedule.	**Medium**	-Projects is seeking pre-commitments. If CMO is unable to provide required support, Projects will staff up as required.	**Low**
Environmental				
Active Liquid Waste Management System unable to handle the volume of flushing waste.	Increase cost for handling waste.	**Low**	-Flushing activities previously executed in other units have produced similar effluents and anticipated volumes. -Projects to identify the system capabilities and arrange for an alternate flushing waste handling process if necessary.	**Low**
Health & Safety				
Unsafe work practices during vendor execution.	Potential for personnel injuries.	**Low**	-Oversight from contract administrators and monitors. -Workplans, Job Safety Analysis and pre-job briefings shall address adherence to procedures. -Implementation of OPG Contract Management processes.	**Low**

Investment				
Improper installation of nozzles.	Re-work required.	**Low**	-Vendors to apply past experience, as similar work was done previously on other units. -Tooling design reviews and mock-up training to be conducted. -Contract administrators and monitors are to ensure that proper procedures are followed. -QS validation to be conducted by Field Engineering.	**Low**
Damage to boiler tubes during flushing activities.	Repair work required leading to a schedule delay.	**Medium**	-Flushing tool design and development to be reviewed and accepted by OPG. Testing as well as mock-up training to be conducted. Enhanced lance provided with video camera. -Contract administrators and monitors are to ensure that proper procedures are followed, and qualified trades are performing the work.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**Jun 2007**	**Jun 2008**	**Components and Equipment Manager**

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Installation of 12 Boiler Nozzles.	12 boiler nozzles are required to be installed in U4.	12 nozzles installed in U4 during P541.	Available for Service (AFS) declaration signed and accepted.	Project Sponsor (Components and Equipment Manager)
2.	Execution of pre and post BCC boiler flushes.	Pre and post BCC Flushing required.	Pre and post BCC flushes executed in support of BCC during P741 (or P641 if schedule is advanced).	Boiler Inspection Report.	Project Sponsor (Components and Equipment Manager)

U4 Boiler Flushing 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Years 2004	2005	2006	2007	2008		Total	LTD This Mth Jan 2005	LTD %
Project Management (OPG)	440	530	410	510	-		**1,890**	440	**23.3%**
Engineering & Drafting (OPG)	140	165	130	170	-		**605**	140	**23.1%**
Material	-	150	550	250			**950**	-	**0.0%**
Installation – PWU, BTU	-	650	90	680	-		**1,420**	0	**0.0%**
Contract – Project Mgmt	35	-	-	-	-		**35**	35	**100.0%**
Contract - Design	0	-	-	-	-		**0**	-	**0.0%**
Contract - Installation	-	3,500	700	3,700	-		**7,900**	0	**0.0%**
Contract - Other	0	-	-	-	-		**0**		**0.0%**
							-		
							-		
							-		
							-		
							-		
							-		
							-		
Interest (Capital Project Only)							-		
Sub Total (excl Contingency)	**615**	**4,995**	**1,880**	**5,310**	**-**	**-**	**12,800**	**615**	**4.8%**
Contingency		770	280	850			**1,900**	**N/A**	**N/A**
Grand Total	**615**	**5,765**	**2,160**	**6,160**	**-**	**-**	**14,700**	**N/A**	**N/A**
2005-2009 Business Plan	1,340	5,000	2,500	4,480	2,500		**15,820**	**N/A**	**N/A**
Variance to Business Plan (excl Contingency)	**(725)**	**(5)**	**(620)**	**830**	**(2,500)**	**-**	**(3,020)**	**N/A**	**N/A**

Removal Costs included in above	**0**
Definition Costs included in above	**0**
Estimate Name, Quality, etc	**Release Quality Est +15% to -10%**
Design Complete:	**40% to 90%**

Reviewed By:

2/17/05
Date:

E.H. Wong
Project Manager

Approved By:

Feb 17/05
Date:

P. Floyd
Eng & Mods Manager (Strat IV)

U4 Boiler Flushing 13 - 49204

Full Release Business Case Summary NA44-BCS-36340-00002-R000

ATTACHMENT "B" **SUPERSEDING COST VARIANCE TABLE**

Not Applicable.

FSA Upgrade Project 10 - 26003

Partial Release Business Case Summary N - BCS - 09076 - 10000 – R000

1/ RECOMMENDATION:

We recommend a Partial Release of $9.3 Million (OM&A) to update the Pickering B and Darlington Fire Safety Assessments (FSAs) in order to comply with the new CSA Standard N293-07 update 01 (Fire Protection for CANDU Nuclear Power Plants). This partial release will also cover the development of the Pickering A FSSA methodology and the CCR changes.

There are several changes to CSA N293-07 (detailed in the Background Section) that call for OPGN to:

- Upgrade the FSA's using new methodology, include new areas, all operating states, structures and components not previously required by CSA N293-95.
- Update FSAs to reflect current plant configuration and deviations from requirements / standards
- Develop a process to maintain the FSA's current with the plant configuration including a process for re-issuance or confirming a "no change" status of the Fire Safe Shutdown Analysis (FSSA) at least once every five (5) years.

The Fire Safety Assessments (FSAs), categorized below, were first written in approximately 2000 and have not been updated since:

1.) Fire Hazard Assessment (FHA) (a set of analyses and assessments for evaluating potential fire hazards as well as the appropriate fire protection systems and features used to mitigate the effects of a fire.)
2.) Fire Safe Shutdown Analysis (FSSA) (an analysis to demonstrate that at least one means of achieving nuclear safety objectives and performance criteria is available.)
3.) Code Compliance Review (CCR) (an assessment for compliance with the applicable sections of the Codes of construction (i.e., the NBCC, and NFCC) and the Codes and Standards referenced therein.)

OPGN does not have the qualified resources to complete these tasks internally. It is therefore recommended that Contractors are engaged to address the issues involving Fire Hazard Assessment (FHA) and Fire Safe Shutdown Analysis (FSSA) and Code Compliance Reviews (CCR) upgrades.

The update of the Pickering A FSSA's and FHA's to incorporate the requirements of the Safe Storage Project is outside of the scope of this project and is being handled separately. **This project does not include any modifications that may arise as a result of the new FSA documentation.**

This is a Release Quality estimate based on Vendor estimates for the FHA/FSSA and CCR Upgrade and Update work. Partial Funding is required at this time to allow for the awarding of contract work. A [redacted]% general contingency is included along with $[redacted] of specific contingencies. Upon completion of the Darlington FHA/ FSSA Vendor work, lessons learned will be incorporated and a Full release BCS will be sought to include the upgrading of the Pickering A FHA and FSSA.

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	None								-
Requested Now	Partial		2,947	4,950	1,488				9,385
Future Funding Req'd	Full			594	2,345				2,939
Total Project Costs		-	2,947	5,544	3,833	-	-	-	12,324
Non Project Costs									-
Grand Total		-	2,947	5,544	3,833	-	-	-	12,324

Investment Type	Class	NPV	IRR	Discounted Payback
Regulatory	OM&A	(7,786)	N/A	N/A

Submitted By:

MA Jusy pp PFT 2009/07/29.
P. Tremblay
S.V.P. Nuclear Programs and Training
Date:

Finance Approval:

R. Leavitt
V.P. Nuclear Finance
Aug 10, 2009
Date:

Line Approval (Per OAR Element 1.1 Project in Budget):

Wayne Robbins
W. Robbins
Chief Nuclear Officer
2009-08-13
Date:

2/ BACKGROUND & ISSUES

The new CSA N293-07 update 01 requires stations to maintain the CCR's and FHA's to reflect the current plant configuration and the FSSA's are to be updated or confirmed at least once every 5 years.

The following is a summary of the significant items which must be upgraded if non compliance cannot be justified:

1.) The FSSA shall consider all areas of the plant within the protected area and exposures to the plant from outside the protected area. (The original FSSA's did not consider all areas of the plant within the protected area, only the areas determined to be related to Nuclear Safety. Also no exposures from outside the protected area were considered.)
2.) The FSSA shall cover fires during all operational modes, including power operation, shutdown or start-up and outages. (The original FSSA's did not consider any operational mode other than full power operation.)
3.) The FSSA shall demonstrate the adequacy of fire protection for radioactive materials outside the reactor to ensure the release of radioactive materials as a result of a fire or fire suppression activities is as low as is reasonably achievable.
4.) Where alternatives or performance-based approaches are implemented, details of any deviation from the requirements and procedures stated in this Standard shall be documented in the code compliance review and considered in the fire hazard assessment. (Alternatives and performance based approaches have not been documented in the stations CCR's. Existing alternatives and performance based approaches will also require re-approval from the Authority Having Jurisdiction (AHJ) to deviate from the newly prescribed codes, where gaps are identified.)
5.) Where a facility requires storage of radioactive or combustible material in areas, rooms, or configurations that do not comply with the requirements of this Standard, a CCR, FHA, and FSSA, are required to demonstrate and document that the proposed configuration will meet the fire protection goals, objectives, and intent of this Standard. Concurrence by the AHJ is required for the deviation. (The existing storage of materials in the stations must be reviewed against the requirements of this standard and removed, brought into compliance or justified and documented as required above.)
6.) CCR's are to cover all areas of the plant as defined by the CSA standard. (The existing CCR's do not cover all systems structures and components of the plants.)

The original compliance date of Mar 2010 has been included in the new Power Reactor Operating Licenses (PROLs) for Darlington and Pickering B. A license amendment is being processed to extend the mandatory compliance date for operational clauses to Dec 2011, however approval has not yet been obtained. Compliance for Pickering A will also be required as part of the Pickering relicensing process.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue							
OM&A							
Capital		(12,324)	(12,324)				
Present Value (PV)		(7,786)	(7,786)				
Net Present Value (NPV)	**N/A**	**(7,786)**	**(7,786)**				
Internal Rate of Return (IRR) %	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Base Case: Not Recommended - Status Quo
The Status Quo is not recommended because this would result in an operating license violation.

Alt. 1: Recommended - Upgrade the Fire Safety Assessments
Phase 1 is to Upgrade the Darlington and Pickering B Fire Safety Assessments, Develop the methodology for Pickering A and Update the Pickering A Code Compliance Review, to bring them into compliance with CSA N293-07 update 01 to meet license conditions in the Darlington and Pickering B Power Reactor Operating Licenses. It is recommended to contract out the FHA, CCR and FSSA upgrades/ updates (Using Phase I FHA/FSSA Vendor for Phase II FHA/FSSA work.). This is to include in house preparation of floor plans in the ESM II system to improve the ability to ensure compliance with respect to staged and stored material. . In house NPPT staff will be involved in the project for development of skills for long term updating of the FSA's.

Alt. 2: Not Recommended - Delay Project
It is not recommended to delay because it will increase the risk to not meeting the compliance date. Other utilities are looking to complete similar work and a delay could cause the FHA/ FSSA upgrade contractors to not be available in time to meet the compliance date.

Alt. 3: Not Recommended - Upgrade the FSA's in House
This alternative is not recommended because OPGN does not have enough qualified staff to complete this work by the deadline. Additionally using qualified contract staff will improve the credibility of the work. No cost estimate has been provided as it is not achievable. In house NPPT staff will be involved in the project for development of skills for long term updating of the FSA's.

Alt 4: Not Recommended - Upgrade the Fire Safety Assessments -Excluding ESM II Floor Plans
Upgrade the Fire Safety Assessments to bring them into compliance with CSA N293-07 update 01 to meet license conditions in the Darlington and Pickering B Power Reactor Operating Licenses with the use of Contractors however this option would exclude the in house preparation of floor plans in the ESM II system. This alternative is not recommended as OPGN has had difficulty with the storage and staging of materials as per recent PINO audits. The new stricter requirements of N293-07 will make this even more challenging. For example stored combustible materials are to be in 2 hour fire rated enclosures. As an alternative the FHA will define the limit of combustibles allowed in each area of the plant. In order to assess any new Transient Material permit the new amount of combustibles would need to be added to the aggregate of other permanent and transient combustible materials in the fire zone and be compared to the limit in the FHA to ensure compliance. The floor plans will identify the existing transient material permits and any storage restrictions enhancing our ability to remain in compliance. The exclusion of the ESM II floor plans from the project would reduce the cost by $[redacted]

Alt. 5: Not Recommended - Upgrade the Fire Safety Assessments Original FHA/ FSSA Vendor
Same as Option 1 except use the original FHA/FSSA Vendor. This option is not recommended as the original vendor was not the successful bidder for the Phase 1 contract, also the Safe Storage FSSA Update bid and duration were substantially greater than the Phase 1 successful bidder.

4/ THE PROPOSAL

- Engage contractors as required (by Sept. 2009) to upgrade /update the CCR's for all 3 sites and the FHA's and FSSA 's for Darlington and Pickering B with the partial release of funds. The original date for License compliance was March 2010, however this date is not achievable and a license amendment request is being processed for Dec 2011. (The full release project work is to include the Pickering A FHA and FSSA upgrades and the updates with respect to transient material. However it is not to include the Pickering A updates of the FSSA and FHA as these will be completed by the Safe Storage Project.)
- Use alternative compliance wherever possible
- Seek CNSC exemption for CCR updates on Non Nuclear Safety Related Buildings
- Produce with in house staff floor plans in the ESM II system to enhance our ability to store and stage material in compliance with the requirements of the new CSA standard. The floor plans will identify any restrictions to the storage of material in the area and any transient and permanent material storage locations.

5/ QUALITATIVE FACTORS

None

6/ RISKS (see Attachment D for details)

Low = 1 to 3		Medium = 4 to 9		[illegible]	
	Impact				
	1	2	3	4	5
Probability 5	5	10	[illegible]	[illegible]	[illegible]
Probability 4	4	8	[illegible]	[illegible]	[illegible]
Probability 3	3	6	9	[illegible]	[illegible]
Probability 2	2	4	6	8	10
Probability 1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact – Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact – Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Station engineering resources are in limited supply and may not be able to support he project.	Contractor rates assumed for engineering work to ensure staff can be hired if not available. Pickering A and B FHA/ FSSA work scheduled to avoid the VBO window.		25							25		16							16
The CSA N293-07 is a rewritten standard with many changes. OPG is the First licensee to Upgrade FSA to the new methodology requirements	Project broken down into 2 phases. Phase 1 was to determine a scope of work and estimate. Phase 1 proceeded at risk from NPPT OM&A funding. The Phase 1 selected Vendors had representation on the CSA Standard Committee and therefore understood the intent of the standard.			20		16				20			12		8				12
The selected FHA / FSSA Vendor did not produce the original documents therefore the details of the preparation are not fully understood and deviations to the required methodology may be identified as the work progresses.	A [redacted] allowance has been added to the FHA/ FSSA vendor estimates.	15								15	3								3
CNSC concurrence to the scope of work has not been obtained due to time limitations.	CNSC concurrence to the proposed scope of work and Alternatives proposed will be obtained as part of the phase 2 work. Selected Phase 1 Vendors have representation on the CSA Standard Committee.					12				12					1				1
DNGS and PNGS B Refurbishment projects will need to complete an integrate safety review and assess/ disposition compliance with the design clauses of CSA N293-07.	All work associated with these projects are to be considered separate and are not part of the scope of this project.	16								16	2								2

BUSINESS CASE SUMMARY

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
The field of completing FHA/ FSSA's is very specialized and there are not many qualified vendors. Other utilities are also looking to Upgrade their FSA's so there is a risk that the vendor will not be available as required by the schedule.	To reduce the contract time the Vendor ASL Quality Assurance audit will be progressed in parallel with the BCS approval. The contracts will be expedited.		20							**20**		15							**15**
Using a Phased approach normally a vendor who completes a scope of work is not eligible to bid on the Phase 2 contract. With FHA/ FSSA work being a very specialized field this could severely limit the Phase 2 vendor selection. (only 2 bids were received for the Phase 1 work.)	The Phase 1 contract was written such that the successful Phase 1 contractor would also receive the phase 2 contract unless OPG was not satisfied with the Phase 1 work.	25								**25**	3								**3**
Delay in approval of project funding. The DNGS and PNGSB PROL compliance date for completion of this work is Mar 1, 2010. While a License amendment request is being processed there is no approval to date and the request is based on OPG proceeding in a timely manner to complete the work.	Process the BCS at high priority.					25				**25**					6				**6**
Qualified staff not available to provide contract support.	NPPT has increased staff levels in anticipation of this work.		16							**16**		4							**4**
Station support may not be available to provide required Vendor information and assessment reviews. (e.g. PNGS VBO)	Pickering A and B FHA/ FSSA work scheduled to avoid the VBO window.		20							**20**		12							**12**
Upgrades to the FSA's may result in the requirement to implement modifications.	If this was allowed to be part of the project then substantial scope/ schedule and cost creep could occur. Any additional field modifications required as a result of the FSA Upgrade project are not part of this	20	25							**25**	8	10							**10**

BUSINESS CASE SUMMARY

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	[illegible]	[illegible]	[illegible]
4	4	8	12	[illegible]	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	project and are to be assessed, approved and completion committed to the CNSC as a separate project.																		
The CSA N293-07 allows the use of Alternatives however these must be approved by the CNSC with no option to appeal a decision. If Alternatives are developed and the FSA upgrades and completed without CNSC concurrence there is a high risk that the end results would not be successfully approved by the CNSC.	Informal discussions with the CNSC Fire Protection staff to gain buy in to the concept of any Alternatives Proposed will be completed as they are developed to ensure the path chosen will be acceptable to the CNSC.					12				12					6				6
CSA N293-07 requires that all operational modes be assessed in the FSSA's. The Vendors estimate has assumed only 2 shutdown states will need to be analyzed. Also the Vendors estimate does not include any allowance to review smoke management as required by the CSA N293-07. There are no Alternatives approved by the CNSC to justify these assumptions.	A specific contingency of [redacted] has been included in addition to the Vendors FHA/ FSSA estimate.	8								8	2								2
Documentation associated with some modifications were not available for Vendor review to assess if there was an impact to the FHA or CCR	A [redacted] allowance will be included in addition to the Vendors Update Costs.	10								10	2								2
Pickering A FHA and FSSA Update work is to be completed as part of the safe storage project. Therefore no funding for these updates is included the estimate. The updates should be completed before the Upgrade work is started. As	The vendor proposed schedule for the Safe Storage Project updates completes the work by Mar 2010. This is well ahead of the July 2010 start date for Pickering A FHA/ FSSA work for this project.	8	20							20	1	9							9

Low = 1 to 3		Medium = 4 to 9		[illegible]	
		Impact			
		1	2	3	4	5
Probability	5	5	10	[illegible]	[illegible]	[illegible]
	4	4	8	12	[illegible]	[illegible]
	3	3	6	9	12	[illegible]
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact — Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
this is a separate project there is a risk of schedule delay if the update work associated with the Safe Storage project is delayed.																			
Additional areas/ buildings may require to be assessed from a code compliance review perspective based on the out come of the a FHA/ FSSA upgrades. This work is unknown at this time.	A specific contingency of [redacted] has been included in addition to the CCR Vendors Upgrade Costs estimate. This work could be completed at the end of the project and not impact other work.	4									1								

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2011	Jun 2012	Martin Tulett

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Equivalencies and alternatives approved by the CNSC		All submitted equivalencies and alternatives approved	CNSC correspondence rejecting alternatives or equivalencies	PINO
2.	FSSA's and FHA's for Darlington Pickering A and Pickering B Upgraded to meet the requirements of CSA N293-07 update 01		No FSA deviatons to the CSA N293-07 update 01 identified in the annual audit	As per the annual audit	PINO
3.	Completion of code compliance reviews on bldgs which have not had one unless dispositioned and accepted by the CNSC.		All required compliance reviews completed or successfully dispositioned and accepted by the CNSC.	As per the annual audit	PINO
4.	FSSA's, FHA's and CCR's updated to incorporate any modifications which have an impact.		All FSSA's, FHA's and CCR's updated to incorporate modifications which have an impact.	As per the annual audit	PINO
5.	All identified deviations dispositioned or modifications initiated.		All identified deviations successfully dispositioned and accepted by the CNSC or modification initiated via the ECC process	As per the annual audit	PINO

Appendix "A"

Glossary (acronyms, codes, technical terms)

AHJ Authority Having Jurisdiction

Code Compliance Review (CCR)
An assessment for compliance with the applicable sections of the Codes of construction (i.e., the NBCC, NFCC, and CSA N293) and the Codes and Standards referenced therein.

CNSC Canadian Nuclear Safety Commission

CSA N293-07 update 01 Fire Protection for CANDU Nuclear Power Plants

ECC Engineering Change Control

ESM II Equipment Status Monitoring program version II

Fire Hazard Assessment (FHA)
A set of analyses and assessments for evaluating potential fire hazards as well as the appropriate fire protection systems and features used to mitigate the effects of a fire.

Fire Safe Shutdown Analysis (FSSA)
An analysis to demonstrate that at least one means of achieving nuclear safety objectives and performance criteria is available.

Fire Safety Assessment (FSA)
A Fire Safety Assessment consists of three elements. A Fire Hazard Assessment, a Fire Safe Shutdown Analysis and a Code Compliance Review

NBCC National Building Code of Canada

NFCC National Fire Code of Canada

NPPT Nuclear Protection Programs and Training

OPGN Ontario Power Generation Nuclear

PINO Performance Improvement and Nuclear Oversight

Upgrades Additional work required to meet the new methodology requirements of N293-07 update 01.

Updates Work required incorporating information related to modifications which have been made since the FSA's were prepared.

Appendix "B"

Project Funding History

$ 000's Release Type	Month	All Existing and Planned Releases (incl contingency) Cumulative Values Year	2009	2010	2011	2012	2013	2014	2015	Later	Total
Partial	Aug	2009	2,947	4,950	1,438						9,335
Full	Oct	2010	2,947	5,544	3,833						12,324
											0
											0
											0
											0
											0
											0
LTD Spent	???	???									0

Comments:

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	0%	SR & D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Income Tax Rate	Generation	PST	No	Interest Rate (Capital)	OMA N/A
Depreciation Rate (Capital)	N/A	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete	N/A	Quality of Estimate	Release + 15% to - 10%	3rd Party Estimate	Not requested
Reviewed by Sponsor	Yes	OPEX used	Yes	Lessons Learned	N/A
Similar Projects	Yes	Budgetary Quote(s)	Yes	First Unit Actual Used	N/A
Cost Sharing	N/A	Contracts in place	Some in place	Competitive Bid	Yes
Fixed Price Contract	Yes	Fee for Service	Yes	Firm Vendor Proposal	Not requested

Comments:
Phase 1 to have vendors develop a scope of work and estimate completed at risk by NPPT.

Rationale for Cost Classification:

There is no outage work associated with this project.

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	???	???	???	???							
	4	???	???									
Pickering B	5	???	???	???	???							
	6	???	???									
	7	???	???									
	8	???	???									
Darlington	1	???	???	???	???							
	2	???	???									
	3	???	???									
	4	???	???									

Comments:
Not applicable to this project.

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk										0
Other										0
Base Case	0	0	0	0	0	0	0	0	0	0
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

See NPV Calculations for Details and Summary

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Base Case	0	0	0	0	0	0	0	0	0	0
Base OM&A										0
Outage OM&A										0
Project OM&A		(2,947)	(5,544)	(3,833)						(12,324)
Recommendation	0	(2,947)	(5,544)	(3,833)	0	0	0	0	0	(12,324)
Net Impact	0	(2,947)	(5,544)	(3,833)	0	0	0	0	0	(12,324)

Comments:

See NPV Calculations for Details and Summary

ONTARIOPOWER GENERATION

OPG Confidential	Page: 15 of 18
BUSINESS CASE SUMMARY	

FSA Upgrade Project 10 - 26003
Partial Release Business Case Summary N - BCS - 09076 - 10000 – R000

Attachment "A"

Project Cost Summary

	$000's OM&A	LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Scores Basis	Project Mgmnt & Support	-	312	250	250					812
	Engineering	-	[redacted]							
	Procurement	-	-	-	-					-
	Construction	-	-	-	-					-
	Other (Training)	-	-	40						40
	Scope/ Estimate Contracts		445	-						445
	CCR Contract Work		[redacted]							
	FSSA/ FHA Contract Work		[redacted]							
	Interest (Capital Project Only)									-
	Project Costs	-	[redacted]							-
	General Contingency		[redacted]							
	Specific Contingency		[redacted]							
	Project Costs	-	**2,947**	**5,544**	**3,833**	-	-	-	-	**12,324**
Cash	**Adjust to Cash Basis +/-**								-	-
	Project Costs	-	**2,947**	**5,544**	**3,833**	-	-	-	-	**12,324**
Funding	**Currently Released**		-	-	-					-
	This Release		2,947	4,950	1,488					9,385
	Future Release		-	594	2,345				0	2,939
	Project Funding	-	**2,947**	**5,544**	**3,833**	-	-	-	0	**12,324**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

		LTD 2008	2009	2010	2011	2012	2013	2014	Later	Total
Budget	**2009-2013 Business Plan**	143	9,974	265	-					10,382
	Variance to Business Plan	**(143)**	**(7,411)**	**4,250**	**3,084**	-	-	-	-	**(220)**
Other	**Removal Costs included above**									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **will be approved by Aug 2009.**

Reviewed By: Ron Piggott 28-07-09

Name Ron Piggott
Project Manager
Date:

Approved By: Don Trylinski 2009/07/28

Name Don Trylinski
Strat IV Manager
Date:

ONTARIO POWER GENERATION

FSA Upgrade project 10 - 26003

Full Release Business Case Summary N - BCS - 09076 - 10000 – R000

Attachment "B"

Project Variance Analysis

	OM&A	LTD Jun 2009	Total Project Last BCS N/A N/A	Total Project This BCS N/A N/A	Variance	Comments
Scores Basis	Project Mgmnt & Support	0			0	
	Engineering	0			0	
	Procurement	0			0	
	Construction	0			0	
	Other	0			0	
	Scope and Estimate Contracts				0	
	CCR Contract Work				0	
	FSSA/ FHA Contract Work				0	
					0	
	Interest (Capital Project Only)				0	
	Project Costs (Scores Basis)	**0**	**0**	**0**	**0**	
	General Contingency				0	
	Specific Contingency				0	
	Project Costs (Scores Basis)	**0**	**0**	**0**	**0**	

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:

Attachment "C"

Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Mth	Yr	
14	8	2009	Partial Release BCS Approved
28	8	2010	Full Release BCS Approved
25	9	2009	Phase 2 CCR Design contract Awarded
29	9	2009	Phase 2 FHA/FSSA Design contract Awarded
16	2	2010	Upgraded and Updated DNGS CCR Report Issued
6	4	2010	Upgraded and Updated PNGS B CCR Report Issued
25	5	2010	Upgraded and Updated PNGS A CCR Report Issued
5	1	2010	DNGS Inspection Testing and Maintenance Compliance reports issued
26	2	2010	PNGS B Inspection Testing and Maintenance Compliance reports issued
16	4	2010	PNGS A Inspection Testing and Maintenance Compliance reports issued
29	11	2010	CNSC Approval of DNGS FHA/ FSSA
10	1	2011	CNSC Approval of PNGS B FHA/ FSSA
19	3	2012	CNSC Approval of PNGS A FHA/ FSSA (Future release)
28	7	2011	Issue DNGS FSSA Floor Plans in ESM II
28	7	2011	Issue PNGS B FSSA Floor Plans in ESM II
16	12	2011	Issue PNGS A FSSA Floor Plans in ESM II (Future release)

A Project Execution Plan (PEP) **will be approved by Aug 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

EQ Discovery Work & Scope Reduction Project 16 - 38458
Partial Release Business Case Summary D - BCS - 03651-10006 – R000

1/ RECOMMENDATION:

Approval is requested for a Partial Release of ~~45.0~~ 42.3 DSP M$ OM&A (including contingency) to allow the Environmental Qualification (EQ) Discovery Work and Scope Reduction Project to continue the work required for Darlington to comply with the EQ requirements in its Power Reactor Operating Licence (PROL) and Design Basis. (This amount includes 9.8 M$ released previously under a Developmental Release). Total project cost estimate is 75.7 M$.

The business objective of this project is to align Darlington with the EQ requirements of its design basis and PROL. This project is a follow-up to Project 16-38457 and will execute EQ scope reduction initiatives. The deliverables for this partial release are outlined in section 4 of this Business Case Summary. This project is required for Darlington to be in compliance with the EQ conditions of its PROL by December 31, 2010.

The previous release was used to:

- Initiate / Complete conceptual and preliminary engineering activities for the required modifications.
- Initiate the required revisions to the EQ design basis document set.

The funding under this release will be used to:

- Complete the detailed engineering activities for the required modifications.
- Complete the required revisions to the EQ design basis document set.
- Complete the analysis required to determine if the project's scope can be reduced in order to reduce the cost of the project and the size of Darlington's sustaining EQ program.
- Initiate the installation activities for selected modifications.
- Execute completion assurance activities for selected equipment.

$000's (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	Developmental		9,779	17,379 DP					
Requested Now	Partial		15,122	~~20,121~~					9,779
Future Funding Req'd	Full			22,843 ~~20,121~~	10,525				32,521 35,243
Total Project Costs		-	24,901	40,242	10,525	-	-	-	33,568 30,646
Non Project Costs									75,668
Grand Total		-	24,901	40,242	10,525	-	-	-	75,668

Investment Type	Class	NPV	IRR	Discounted Payback
Regulatory	OM&A	-36.0 M$	N/A	N/A

Submitted By:

W. Robbins 2009-05-15
Senior Site Vice-President Darlington Date

Finance Approval:

D. Hanbidge June 26/09
VP, Corporate Finance Date:

Line Approval (Per OAR Element 1.1 Project in Budget)

J. Hankinson
President & CEO Date

2/ BACKGROUND & ISSUES

The Ontario Power Generation Nuclear (OPGN) Environmental Qualification (EQ) program establishes an integrated and comprehensive set of requirements that provide assurance that essential equipment can perform as required if exposed to harsh design basis accident conditions and that this capability is preserved over the life of the plants. Under Condition 7.1 of its Power Reactor Operating License (PROL), Darlington must implement a program that is traceable, auditable and meets the OPGN requirements for EQ.

Requirements for EQ at the Darlington Nuclear Generation Station (DNGS) were first spelled out in the Construction License and formalized in 1978 with the first issue of the Design Guide. EQ was in its infancy and formal EQ requirements did not apply to other CANDU stations. In the absence of Corporate, or National standards for EQ, a Darlington specific program manual was developed to provide governance for implementation of EQ. The list of equipment required to be qualified, the EQ Safety Related Component List (EQSRCL), was developed in a non-procedural, non-auditable manner and EQ was implemented at DNGS over the period of 1986 to 1992.

The EQ program was handed over from Design & Construction to Operations in 1992. Lack of focus on the EQ sustaining program and the resultant degradation in component condition prompted the IIP EQ Restoration Program (Project EN009) in 1997. In November 1999, the CNSC proposed an amendment that became a part of the Darlington's PROL requiring that the station provide evidence that required systems, components, protective barriers and structures in the facility are environmentally qualified by June 30, 2004.

The IIP Project was closed in 2001, with some scope necessary to comply with the PROL Condition outstanding. The transition plan identified the work to be completed, with an expectation that the majority of the issues would be completed by the end of 2003.

In May 2003, the CNSC provided acceptance criteria to clarify what was required to satisfy the PROL condition. At the direction of the Chief Nuclear Engineer the remaining EQ work was divided into two projects: one to complete activities necessary to satisfy the PROL condition due June 30, 2004, and a second to complete CNSC EQ commitments due after June 30, 2004 and establish a sustaining EQ Program.

The EQ Recovery Project (16-38411), which was completed June 30, 2004, involved completing the outstanding EQ assessments, completing gap analysis for components with a limited life and scheduling the resolution of issues remaining after June 30, 2004. Upon completion of project 16-38411, another project, 16-38457 EQ Closure and Component Replacement was initiated to resolve the outstanding issues by December 31, 2010.

The EQ Closure and Component Replacement Project (16-38457) was initiated in 2004. Under this project Darlington has followed the OPGN EQ list development process to update its EQSRCL; this process provides full traceability and compliance with the EQ design basis. As a result of an unexpected large number of deficiencies being identified a scope optimization study was conducted on Darlington's EQ program which made several recommendations on how Darlington could reduce the size of its EQ program.

This project is a follow up to Project 16-38457 established to execute EQ scope reduction initiatives. Under the developmental release conceptual / preliminary engineering activities have been initiated and revisions to the EQ design basis document set have been initiated. Analysis has been completed to verify the validity of the Critical Breaks Approach to EQ which was established through NSS analysis under Project 16-38457. While this approach does represent a significant reduction in scope it also identified further opportunities for scope reduction.

As outlined in section 4 this partial release will:

1. Continue with the necessary engineering work to implement the critical breaks approach.
2. Initiate the installation of the modifications required to implement the critical breaks approach.
3. Complete the necessary analysis to determine if the scope of the project can be further reduced.
4. Complete the required revisions to affected documents.
5. Execute completion assurance activities.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue							
OM&A							
Capital		(75,668)		(71,581)	(68,981)		
Present Value (PV)		(39,887)	(35,993)	(37,762)	(36,411)		
Net Present Value (NPV)	**N/A**	**(39,887)**	**(35,993)**	**(37,762)**	**(36,411)**		
Internal Rate of Return (IRR) %	N/A						
Discounted Payback (Yrs)	N/A						

Base Case: Not Recommended - Fully Implement EQ to Group 1 & Group 2 Equipment
The base case is to complete the necessary modifications in order to fully EQ all Group 1 support components as per the existing design basis. This is not recommended since it would significantly increase the cost of the project and would result in a sustaining program that the station would not be able to maintain with their current resource levels.

Alt. 1: Recommended - Implement Critical Breaks Approach
The Critical Breaks Approach was developed by NSS and involves implementation of a reduced set of modifications which will ensure that any remaining EQ inadequacies will have a negligible safety impact. The modifications include work on critical breakers and HVAC control circuits in order to support both divisions of Class III power.

This is the recommended approach since it involves implementation of a reduced set of modifications with minimal impact on the current design / licensing basis. In addition to the necessary modification work analysis will be completed to determine if the scope of the project can be reduced further.

Alt. 2: Not Recommended - Implement EQ to Group 2 Equipment Assisted by Standby Generators
This approach assumes that Group 2 heat sinks are qualified for secondary-side line breaks and portions of Class III power are also credited to support Group 2 heat sinks. This would involve a limited set of modifications to the Class III system to allow the Standby Generators to support Group 2. This approach is not recommended at this time because it is based on preliminary analysis and further work is required to verify the assumptions made.

Alt. 3: Not Recommended - EQ only Group 2 Equipment
This approach assumes that only Group 2 heat sinks will be qualified for secondary-side line breaks. All EQ scope related to Group 1 heat sinks would no longer be required. While this approach significantly reduces the project scope it is not recommended since it would also significantly reduce the stations operating margin.

Alt 4: Not Recommended -

Alt. 5: Not Recommended -

4/ THE PROPOSAL

The proposal is for the partial release of $~~35.2~~ 32.5 M to allow the EQ Discovery work and Scope Reduction Project to:

1. Complete detailed design activities and initiate installation activities to environmentally qualify the following:
   - Deaerator Storage Tank Level Transmitters
   - Solenoid Valves for Low Pressure Service Water Temperature Control Valves
   - Class III Power
   - Class IV Power
   - Heating, Ventilation and Air Conditioning equipment associated with Steam Protected Rooms
   - Power Supply (Motor Control Center 363) for Fan 29
   - Service Water Pneumatic Valve 501
   - Fuelling Machine D_20 Injection Valves
   - Auxiliary Boiler Feed Pumps
   - Shutdown Cooling Temperature Control Valves
   - Primary Heat Transport pressurizer heaters
   - Control Power (Motor Control Center 259/260) for Fan 1/Fan 2/Fan 3/Air Conditioning Unit 1
   - D_20 Recovery Isolation Valve
   - Wet Room Transmitters

   In addition, analysis and modification work will be completed as required to credit the Column Line 11 wall as a steam barrier.

   Essential project scope comprises equipment and systems which must be qualified to satisfy the license condition. This essential scope will be given priority to ensure that all field modifications on these systems are completed by December 31, 2010 in order to meet the license condition. The balance of scope related to equipment and systems which must be qualified in order to ensure the station has sufficient operating margin.

2. Complete analysis required to pursue scope reductions associated with reactor heat sink qualification methodology (from the "Critical Breaks Approach including Group 1 Heat Sinks" to "Group 2 Heat Sinks assisted by Standby Generators").

3. Complete the necessary updates to:
   - Technical Basis Documents
   - EQ List Development Packages
   - EQ Assessment Part 1's (evaluation of equipment EQ requirements, including configuration, maintenance, and replacement requirements)
   - EQ Assessment Part 2's (establishes basis for EQ of a manufacturer's component by evaluation of test and analysis documentation)
   - Room Conditions Manual
   - Safety Report
   - Operation / Maintenance document set

4. Perform the required completion assurance activities. This will include field verification walk-downs and documentation and PassPort reviews.

All scope additions and changes are reviewed by a Darlington EQ Steering Committee for approval, in addition to normal Project Approval Committee and Site Management Board meetings. In addition, field walk downs are being conducted to resolve outstanding configuration management issues.

5/ QUALITATIVE FACTORS

Environmental Qualification compliance and sustainability are license requirements. Qualitative benefits of the project are:

1. An improved ability to contain and minimize damage or loss of the asset due to a harsh design basis accident.
2. An increase in public and employee safety.
3. A manageable EQ program which Darlington will be able to sustain.

6/ RISKS (see Attachment D for details)

Low = 1 to 3	Medium = 4 to 9	High = 10 to 25			
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Probability x Impact – Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Probability x Impact – Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
2009 cash-flow may not allow all design work to be completed by year end which could impact the projects ability to complete all installations by December 2010	Provided design contracts can be released in a manner that would necessitate additional funding the project will submit a PCRAF to transfer funding from the 2010 budget and/or draw down on project contingency in order to advance design work.	4	20	4	4	8	4	4	4	**20**	8	12	4	4	4	4	4	4	**12**
Modifications are not completed prior to December 31, 2010 in compliance with the PROL.	1. Design Agencies are being used to expedite all designs. 2. Weekly meetings are being held with all Design Agencies to monitoring the schedule and resolve any issues which arise. 3. A dedicated EQ Design Section within OPG has been established to monitor the Design Agencies. 4. The project has regular meetings with all stakeholders. 5. Workplans / assessing are being completed in parallel with detailed design so work can be advanced. 6. The PROL condition is being reviewed to determine if completing the modifications on all Group 2 systems would satisfy it. Allowing the modifications to Group 1 systems to continue into 2011 if required.	3	12	3	6	15	3	3	12	**15**	2	8	2	4	6	2	2	8	**8**
Unavailability of materials due to compressed design / installation	1. Long lead materials are being identified and order early in the	3	15	3	3	3	3	3	3	**15**	2	6	2	2	2	2	2	2	**6**

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	10	15	20	25
4	4	8	12	16	20
3	3	6	9	12	15
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
schedules	design phase. 2. Supply Chain has appointed a SPOC to assist in material procurement. 3. Where possible Design Agencies are taking material lead times into account when selecting material.																		
Unavailability of Design resources.	1. The project is utilizing all of OPGs preferred vendors as well as additional vendors with EQ expertise. 2. Selected designs are being completed by internal resources.	3	12	3	3	3	3	3	3	12	2	8	2	2	2	2	2	2	8
Unavailability of OPG support group resources	Issues with obtaining support from internal resources are communicated upward so station management can set appropriate work priorities.	3	9	3	3	3	3	3	3	9	2	4	2	2	2	2	2	2	4
Significant discoveries during the inspection of column line 11.	1. Standard repairs details have been developed for expected deficiencies. 2. Use of OPEX from previous inspection campaigns at PNGS / DNGS.	3	9	3	3	3	3	3	3	9	3	6	3	3	3	3	3	3	6
Cost estimates for several designs were based on preliminary information since conceptual design has not been completed	Contingency has been included to account for potential cost increases.	6	9	3	3	3	3	3	3	9	3	4	2	2	2	2	2	2	4
Material quality issues with components being replaced causing delays to the schedule / cost increases.	1. Use of qualified suppliers / 3rd party dedicators. 2. Use of OPG Source Surveillance Dept. 3. Additional testing / receipt inspection will be specified if deemed necessary.	2	10	8	2	2	2	2	4	10	2	6	4	2	2	2	2	4	6
Discovery of significant issues during field verification walkdowns during	1. OPEX from D811 / 2008 online walkdowns showed that no significant	3	9	3	6	3	3	3	3	9	3	3	3	3	3	3	3	3	3

Low = 1 to 3		Medium = 4 to 9		High = 10 to 25		
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
D1041 / D1021.	findings are expected. 2. Contingency plans will be developed prior to the 2010 outages based on OPEX from previous walkdowns.																		
Equipment which is believed to be qualifiable through an EQA is found not to be.	1. A feasibility analysis is being completed to identify if there are any risks associated with EQA preparation / revision. (TCD: Q2-2009) 2. EQA Part 2s are being prepared / revised on an accelerated schedule.	2	8	2	2	2	2	2	2	8	2	4	2	2	2	2	2	2	4
Identification of new modification scope during EQLDP / TBD revisions.	1. All high risk EQLDP revisions have been completed. 2. A review of the TBDs has been completed to identify any potential areas of concern. 3. Remaining EQLDP / TBD revisions are scheduled to be completed by the end of 2009.	8	16	4	4	4	4	4	4	16	2	8	2	2	2	2	2	2	8

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	TBD in Next Release	TBD in Next Release	Director of Engineering

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

AFS:	Available for Service
BCS:	Business Case Summary
CNSC:	Canadian Nuclear Safety Commission
DNGS:	Darlington Nuclear Generating Station
EQ:	Environmental Qualification
EQA:	Environmental Qualification Assessment
EQLDP:	Environmental Qualification List Development Package
EQSRCL:	Environmental Qualification Safety Related Components List
FM:	Fueling Machine
HVAC:	Heating, Ventilation and Air Conditioning
IEV:	Impact on Economic Value
IRR:	Internal Rate of Return
IPP:	Integrated Improvement Plan
LPSW:	Low Pressure Service Water
LT:	Level Transmitter
LTD:	Life to Date
MCC:	Motor Control Center
N/A:	Not Applicable
NPV:	Net Present Value
NSS:	Nuclear Safety Solutions Inc.
OAR:	Organizational Authority Register
OM&A:	Operating, Maintenance, and Administration
OPEX:	Operating Experience
OPG:	Ontario Power Generation
OPGN:	Ontario Power Generation Nuclear
PCRAF:	Project Change Request Authorization Form
PEP:	Project Execution Plan
PHT:	Primary Heat Transport
PIR:	Post Implementation Review
PNGS:	Pickering Nuclear Generating Station
PROL:	Power Reactor Operating License
PV:	Pneumatic Valve
SG:	Standby Generator
SPOC:	Single Point of Contact
T&M:	Time and Material
TBD:	Technical Basis Document

Appendix "B" Project Funding History

$ 000's Release Type	Month	Year	2009	2010	2011	2012	2013	2014	2015	Later	Total
		All Existing and Planned Releases (incl contingency) Cumulative Values									
Developmental			9,779								9,779
Partial			24,901	17399.000 ~~20,124~~							42300 ~~45,022~~
											0
											0
											0
											0
											0
											0
LTD Spent	Mar	2009									0

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	None	SR & D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Income Tax Rate	Non Generation	PST	N/A	Interest Rate (Capital)	OMA N/A
Depreciation Rate (Capital)	N/A	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete	Up to - 40%	Quality of Estimate	Budget + 30% to - 15%	3rd Party Estimate	No
Reviewed by Sponsor	No	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote(s)	No	First Unit Actual Used	No
Cost Sharing	No	Contracts in place	Some in place	Competitive Bid	No
Fixed Price Contract	No	Fee for Service	No	Firm Vendor Proposal	No

Comments:

Rationale for Cost Classification:

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A										
	4	N/A										
Pickering B	5	N/A										
	6	N/A										
	7	N/A										
	8	N/A										
Darlington	1	Jun	2018	935	88%							
	2	Sep	2016									
	3	Mar	2020									
	4	Dec	2021									

Comments:

Appendix "C"

Financial Model – Assumptions
Impact on Operations

Impact on Revenue

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Rate KWH										
Probability										0.0%
Consequence										0
Risk										0
Other										0
Base Case	0	0	0	0	0	0	0	0	0	0
Probability										0.0%
Consequence										0
Risk										0
Other										0
Recommendation	0	0	0	0	0	0	0	0	0	0
Net Impact	0	0	0	0	0	0	0	0	0	0

Comments:

Impact on OM&A

$000's	Present	2009	2010	2011	2012	2013	2014	2015	Later	Total
Base OM&A										0
Outage OM&A										0
Project OM&A										0
Base Case	0	0	0	0	0	0	0	0	0	0
Base OM&A										0
Outage OM&A										0
Project OM&A		24,901	40,242	10,525						75,668
Recommendation	0	24,901	40,242	10,525	0	0	0	0	0	75,668
Net Impact	0	24,901	40,242	10,525	0	0	0	0	0	75,668

Comments:

Cash flows and committed milestones assume that this BCS receives OAR approval by 15Jun2009.

EQ Discovery Work & Scope Reduction Project 16 - 38458
Partial Release Business Case Summary D - BCS - 03651 - 10006 – R000

Attachment "A"

Project Cost Summary

	$000's OM&A	LTD 2008	This BCS 2009	This BCS 2010	Future 2010	Future 2011	2012	2013	Later	Total
Scores Basis	Project Mgmnt & Support		2,412	1,993	1,993	3,450				9,847
	Engineering		[redacted]							
	Procurement									
	Construction									
	Other									
										-
										-
										-
										-
	Interest (Capital Project Only)									-
	Project Costs	-	[redacted]							
	General Contingency									
	Specific Contingency									-
	Project Costs	-	**24,901**	**17,399**	**22,843**	**10,525**	-	-	-	**75,668**
Cash	Adjust to Cash Basis +/-								-	-
	Project Costs	-	**24,901**	**17,399**	**22,843**	**10,525**	-	-	-	**75,668**
Funding	Currently Released		9,779							9,779
	This Release		15,122	17,399						32,521
	Future Release				22,843	10,525			(0)	33,368
	Project Funding	-	**24,901**	**17,399**	**22,843**	**10,525**	-	-	**(0)**	**75,668**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget	2009-2013 Business Plan		18,401	24,950		3,650				47,001
	Variance to Business Plan	-	**(0)**	**5,792**		**2,375**	-	-	-	**8,167**

Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **is not required** .

Reviewed By: June 19/09
D. Somerville
Project Manager
Date:

Approved By: 2009 Jun 19
T. Chong
Strat IV Manager
Date:

EQ Discovery Work & Scope Reduction Project 16 - 38458
Partial Release Business Case Summary D - BCS - 03651 - 10006 – R000

Attachment "B" **Project Variance Analysis**

	OM&A	LTD Mar 2009	Total Project Last BCS Feb 2009	Total Project This BCS Apr 2009	Variance	Comments
Scores Basis	Project Mgmnt & Support		6,040	9,847	3,807	See Note 1.
	Engineering		[redacted]			See Note 1.
	Procurement		[redacted]			See Note 2.
	Construction		[redacted]			
	Other		[redacted]			See Note 3.
					0	
					0	
					0	
					0	
	Interest (Capital Project Only)				0	
	Project Costs (Scores Basis)	0	[redacted]			
	General Contingency		[redacted]			
	Specific Contingency		[redacted]			
	Project Costs (Scores Basis)	0	76,020	75,668	-352	

Other	Removal Costs included above				0	
	Inventory to be written off				0	
	Spare Parts in Inventory				0	

Comments:

Note 1:

The developmental BCS assumed that there would be 12 modifications with the possibility of additional packages discovered during TBD / EQLDP preparation / revision. The cost estimates for these modification packages were based on preliminary information and contingency was included to account for the quality of estimates.

The projects scope now has 16 modification packages included in it and engineering has progressed on several packages allowing more detailed estimates to be prepared. This has resulted in additional funding requirements for design contracts and additional project management staff being hired to adequately monitor and progress the work.

Note 2:

Material costs are low compared to the total cost of the project because several modifications require only EQ qualified splice kits and/or qualified solenoid valves / transmitters which are relatively inexpensive. The installation cost is primarily driven by the labour requirements to perform and verify the work.

Note 3:

This $[redacted] is the estimated contract cost for the EQ completion assurance packages. This is not actually a variance, in the previous estimate this cost was included in the Contract – Design line.

Attachment "C"

Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	**Mth**	**Yr**	
30	Apr	2009	EQ Program Draft PEP
15	May	2009	CNSC Submission for Group 1 Heat Sinks
19	May	2009	NOC Meeting
21	May	2009	Partial Release approved by Board of Directors
30	Jun	2009	EQ Design Inputs Complete
30	Jun	2009	All Modifications & Baseline Maintenance (BM) & Dispositions Identified
30	Jun	2009	Strategic Sourcing Plan in place
30	Jul	2009	EQA Part II's Complete
30	Oct	2009	Long Lead Material Ordered (CAT ID identified)
30	Nov	2009	Technical Basis Documents Final Completion
15	Dec	2009	EQL Complete
15	Dec	2009	Room Conditions Complete
31	May	2010	Engineering Complete
31	May	2010	Final Release approved by Board of Directors
30	Jun	2010	Assessing Complete
30	Jun	2010	EQPR Complete
29	Oct	2010	All Baseline Maintenance Identified (last walk-down)
01	Dec	2010	Field Implementation Complete
30	Jun	2011	EQ Installation Instruction Complete
30	Jun	2011	EQ Training Program
30	Jun	2011	Closeout Complete

A Project Execution Plan (PEP) **will be approved by Jun 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%

Attachment "D"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Probabilistic Safety Assessment Upgrade 10 - 62440

Partial Release Business Case Summary N-BCS-03500-10000-R000

1/ RECOMMENDATION:

Approval is requested for a partial release of $11.3 Million (including contingency) OM&A project funding to initiate the upgrading the Darlington, Pickering A and Pickering B Probabilistic Safety Assessments (PSA - also known as Probabilistic Risk Assessment or PRA).

The business objectives of this project are to:

- Upgrade the Darlington and Pickering B Probabilistic Safety Assessments to bring them into compliance with their current Power Reactor Operating Licenses. The respective operating Licenses for both stations (revised and reissued by the CNSC in 2008) mandate that by December 31, 2010, each station must have a PSA that is compliant with the requirements of CNSC Regulatory Standard S-294 "Probabilistic Safety Assessment (PSA) for Nuclear Power Plants". The development, maintenance and use of PSA is also mandated by the requirements of the Corporate Nuclear Safety Policy and by the requirements of the corporate Risk and Reliability Program N-PROG-RA-0016.
- Upgrade the Pickering A Probabilistic Safety Assessment to be compliant with Regulatory Standard S-294, which is anticipated to be required in the Pickering A Power Reactor Operating License renewal in 2010.
- Develop sustainable in-house PSA expertise which will support:
  - The regulatory trend towards risk-based decision making in relation to assessment of emergent plant issues
  - The industry trend towards use of PSA for business risk assessments and for business optimization decisions related to on-line and outage maintenance strategies and scheduling.

The cost estimate is based on a project execution plan provided by the primary contractor and input from potential secondary contractors. Costing is based on experience to date with recent risk model upgrades and projected costs for inclusion of evaluation of internal events such as fire and external events such as seismic incidents.

The funding estimate also includes the requirements for OPG staff for project management and station support staff (7 full time equivalents) up to the end of 2010 to provide expert detailed review of contractor product and to develop a sustaining in-house expertise in the PSA field.

$000's (incl contingency)	Funding	LTD 2008	2008	2009	2010	2011	2012	Later	Total
Currently Released	None	-	-	-	-	-	-	-	-
Requested Now	Partial	-	1,800	10,200	-	-	-	-	12,000
Future Funding Req'd	Full	-			10,400	4,400	-	-	14,800
Total Project Costs		-	1,800	10,200	10,400	4,400	-	-	26,800
Other Costs									-
Ongoing Costs									-
Grand Total		-	1,800	10,200	10,400	4,400	-	-	26,800

Investment Type	Class	(IEV) Impact on Ec Value	IRR	Discounted Payback
Regulatory	OM&A	(15,800)	N/A	N/A

Submitted By:

R C Morrison 8 Sep 08

R.C. Morrison Date:
Vice President & Chief Nuclear Engineer

Finance Approval:

D. Hanbidge Date:
Senior Vice President & Chief Financial Officer

Line Approval (Per OAR Element 1.2 Project not in Budget):

J. Hankinson Jan 9/09
President & Chief Executive Officer Date:

2/ BACKGROUND & ISSUES

In April 2005 following industry consultation (including OPG through the CANDU Owners Group), the Canadian Nuclear Safety Commission published Regulatory Standard S-294 which mandates that each nuclear power plant licensee carry out plant specific Level 2 Probabilistic Safety Assessments. A probabilistic safety assessment (also known as a probabilistic risk assessment) is a comprehensive and integrated assessment of the safety of the plant or reactor. The safety assessment considers the probability, progression and consequences of equipment failures or transient conditions to derive numerical estimates that provide a consistent measure of the safety of the plant or reactor. The regulatory standard requires that Canadian utilities have probabilistic safety assessments consistent with international standards. During the review process, the industry questioned need for a probabilistic safety assessment when there was no regulatory context for their usage. The regulator decided on a step-wise process whereby the probabilistic safety assessments will be put in place first to be followed by risk limits and processes.

A Level 1 probabilistic safety assessment identifies and quantifies the sequence of events that may lead to the loss of core structural integrity and massive fuel failures. A Level 2 probabilistic safety assessment starts from the Level 1 results and provides an analysis of containment behaviour, the radionuclides released from the failed fuel and a quantification of releases to the environment.

The Darlington and Pickering B Power Reactor Operating Licenses, as revised and re-issued by the Canadian Nuclear Safety Commission in 2008, mandate that both stations must have a probabilistic safety assessment compliant with the requirements of Regulatory Standard S-294 by December 2010. (Discussions between OPG and regulatory staff prior to the Darlington license re-issue had suggested that the license condition would be to provide a plan to bring it into compliance with S-294 with 2012 as the planned completion.) It is anticipated that an S-294 compliant probabilistic safety assessment will be required for Pickering A in the next issuance of its Power Reactor Operating License in 2010.

The Corporate Nuclear Safety Policy and Corporate Risk and Reliability Program also mandate the development, maintenance and use of probabilistic safety assessments. Probabilistic safety assessments will support the regulatory trend towards risk-informed decision making. Industry experience in jurisdictions requiring Level 2 probabilistic safety assessments indicates that risk-informed decision making has resulted in relaxation of deterministic limits to continuing operation, thereby avoiding shutdowns that otherwise would have occurred. Probabilistic safety assessments will also be required to support regulatory approvals of plant life extensions.

The Darlington Probabilistic Safety Evaluation was issued in 1987 and a "draft" Darlington Risk Assessment was developed. This draft document, although in current use, requires a major revision in order to accurately reflect current plant operation and to comply with the specifications of Regulatory Standard S-294. Preliminary work on the Darlington upgrade is currently in progress.

The Pickering B Risk Assessment was updated and issued in 2007. This probabilistic safety assessment is essentially compliant with Level 1 and Level 2, but requires revision to address regulatory comments.

The current Pickering A Power Reactor Operating License does not require an S-294 compliant assessment. The Pickering A Probabilistic Risk Assessment requires updating of the Level 1 and Level 2 analyses to bring it into compliance with Regulatory Standard S-294.

The existing probabilistic risk assessments have already been used to improve public safety, as discussed in examples below, and the upgrades are expected to identify additional areas for improvement.

- The Pickering A probabilistic risk assessment was used to identify improvements and support restart following Unit 1 and Unit 4 refurbishment.
- The work completed on the Darlington upgrade has already identified gaps in operating documentation and surveillance programs as well as deficiencies that were addressed through operability evaluations.

Due to the increased complexity and cost imposed by the new license conditions and the compressed time frame for completion, it is proposed to manage the upgrade to license compliance as a project, with appropriate project management, augmentation of resources, vendor oversight and station support staffing.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ 000's	Status Quo	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2 Delay	Alt 3	Alt 4	Alt 5
Revenue							
OM&A		(26,800)	(26,800)	(18,800)			
Capital							
NPV (after tax)		(15,896)	(15,896)	(14,951)			
Impact on Economic Value (IEV)	N/A	(15,896)	(15,896)	(14,951)			
IRR%	N/A	N/A	N/A	N/A			
Discounted Payback (Yrs)	N/A	N/A	N/A	N/A			

Status Quo - Not Recommended

Status quo is not recommended. The current Darlington and Pickering B PSAs currently do not comply with S-294 requirements. Darlington and Pickering B will be in non-compliance with their respective PROL license conditions as of Dec 31, 2010 and risk regulatory action. The CNSC will most probably impose the S-294 compliance on Pickering A in its next PROL. There is very low probability that the CNSC will rescind the regulatory document or license condition requiring a level 2 PSA.

Alternative 1 - Complete PSA to Meet License Conditions - Recommended

Upgrade the Darlington and Pickering B Probabilistic Safety Assessments to bring them into compliance with Regulatory Standard S-294 by their respective compliance dates. Upgrade the Pickering A Probabilistic Safety Assessment to bring into compliance with anticipated regulatory requirement. Provide corporate project management and oversight, create separate station organization to execute the project, interface with the regulator and to provide vendor support through to completion.

Alternative 2 - Delay Project - Not Recommended

Delay of project is not recommended as the schedule completion by the license date is already at risk. The probability of acquiring a license amendment extending the deadline for full compliance is very low unless significant progress can be shown.

Alternative 3 – - Not Recommended

NA

Alternative 4 – - Not Recommended

NA

Alternative 5 – - Not Recommended

NA

4/ THE PROPOSAL

This release of the project will initiate the work to update the probabilistic safety assessments of Darlington and Pickering B to bring them into compliance with Regulatory Standard S-294 by Dec 31, 2010 as mandated by the respective current Power Reactor Operating Licenses, and begin work on the Pickering A probabilistic safety assessment as described below:

Develop S-294 Compliant Probabilistic Safety Assessment for Darlington

The probabilistic safety assessment of Darlington will be upgraded in four interdependent phases, as listed below.

- Phase 1: Update Level 1 probabilistic safety assessments (excluding fire and seismic events).
- Phase 2: Develop Level 2 probabilistic safety assessment models (excluding fire and seismic events).
- Phase 3: Address remaining S-294 gap issues including disposition of other external events such as airplane crash, intense precipitation, tornadoes, rail line explosion, rail line toxic gas release, transportation accident, low lake level, meteorite strike, and geomagnetic storms.
- Phase 4: Develop Level 1 and Level 2 assessment models for fire and seismic events.

Develop S-294 Compliant Probabilistic Safety Assessment for Pickering B

This phase of the project will revise the existing probabilistic safety assessment to address regulatory comments and initiate work on Level 1 and Level 2 fire and seismic probabilistic safety assessment, along with disposition of other external events described above. The extent of the probabilistic safety assessment will depend on the end-of-life decision for Pickering B.

Develop S-294 Compliant Probabilistic Safety Assessment for Pickering A

This phase of the project will be to begin the update the Level 1 probabilistic safety assessment to incorporate identified issues, design changes such as permanent Inter-Station Transfer Bus design, incorporation of Unit 2 and Unit 3 Safe Storage end states and other design changes as well as development of the data file necessary for the Level 2 analysis.

Develop Sustainable Internal Expertise for Probabilistic Safety Assessment

Develop sustainable internal probabilistic safety assessment expertise which will support:

- Risk-informed decision making on regulatory issues and response to emergent plant conditions.
- Business risk assessments and optimization decisions.

The project will meet the following overall requirements:

1. A formal quality assurance process for completing a probabilistic safety assessment will be established and applied.
2. Models will reflect the plant as built and operated as closely as reasonably achievable within limitations of probabilistic safety assessment technology and consistent with risk impact.
   - Both internal and external events will be included.
   - At-power and shutdown modes will be included.
   - Sensitivity analysis, uncertainty analysis and importance measures will be included.
3. Models will be developed using assumptions and data that are realistic and practical.
4. The level of detail of the probabilistic safety assessment will be consistent with plant testing and configuration management programs.
5. Canadian Nuclear Safety Commission acceptance of the methodology and computer codes to be used for the probabilistic safety assessment will be obtained.

The project cost is based on vendor budgetary estimates, and experience with preliminary vendor work on PSA revision and considers the increased complexity imposed by the requirement for S-294 compliance and increased scope required to complete the fire and seismic portions of the PSA.

The estimate includes the cost to establish corporate oversight and to create dedicated PSA project teams at the stations to manage and execute the project, provide oversight of vendor activities and costs, provide expert review of vendor product, to provide regular interface with the regulator and for the development of a sustaining in house PSA capability.

Seven Full Time Equivalent employees (FTEs) are required on the station project teams for the duration of the project

5/ QUALITATIVE FACTORS

The existing probabilistic risk assessments have already been used to improve public safety, as discussed in examples below, and the upgrades are expected to identify additional areas for improvement.

- The Pickering A probabilistic risk assessment was used to identify improvements and support restart following Unit 1 and Unit 4 refurbishment.
- The work completed on the Darlington upgrade has already identified gaps in operating documentation and surveillance programs as well as deficiencies that were addressed through operability evaluations.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Complexity of analysis is greater than expected	Budgeted cost exceeded	**High**	Project team to determine acceptable level of complexity. Contingency funding identified in this BCS	**Low**
Scope				
Fire and Seismic PSA not required in previous regulation	Amount of work is more than anticipated resulting higher than budgeted costs	**High**	Initiate as soon as possible and use vendor with previous experience in seismic / fire assessments. Contingency funding identified in this BCS.	**Low**
Analysis reveals situations that require shutdown of one or more units.	Loss of revenue and increased costs while solution to analysed condition is implemented.	**High**	Discovery Issue Resolution Process and Technical Operability Evaluation processes will be used to address issues identified during analysis. Analysis will also support risk-informed decisions by the regulator on increasing the duration of shutdown clocks.	**Low**
Analysis reveals safety deficiencies that require plant modifications to address.	Increased costs as modifications are implemented	**Medium**	Analysis will be used to support risk-informed decisions on proceeding with plant modifications. Proposed modifications will be assessed and prioritized by the AISC process to ensure spending ceilings are maintained.	**Low**
Schedule				
Rework of submitted analyses	Delay in completing analysis work with potential to miss license condition.	**High**	Use staged reviews to minimize rework time.	**Low**

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Resources				
There is a limited pool of experienced probabilistic risk analysts in Canada.	Completing the required analysis by the Darlington and Pickering B license condition date may be missed due to the volume of work.	**High**	Update of the Level 1 and 2 internal event analyses to be completed by the current vendor of probabilistic risk assessment services. Development of the fire, seismic and other external event analyses to be sourced from vendors in Canada and the United States with experience in fire and seismic analysis. Third party review of the analyses will be sourced from vendors in the United States.	**Low**
Technical				
Quality / Methodology	Schedule delay	**High**	Vendor to use industry standard methodology. Station Team to review vendor product. Independent Third Party review.	**Low**
Regulatory				
Regulator rejects analysis due to methodology, data and assumptions	Delay in completing analysis work with potential to miss license condition.	**High**	Staged review by regulator. Establish update process similar to Safety Report update. Vendor to use industry standard methodology. Third party review. Experienced vendors.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
TBD in Next Release	TBD in Next Release	TBD in Next Release	

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.					
2.					
3.					
4.					
5.					

Appendix "A" Glossary (acronyms, codes, technical terms)

CNSC: Canadian Nuclear Safety Commission

DARA: Darlington A Risk Assessment

Level 1 PSA: Probabilistic Safety Assessment of Core Damage Frequency

Level 2 PSA: Probabilistic Safety Assessment of Large Release Frequency

NSS: Nuclear Safety Solutions

PRA: Probabilistic Risk Assessment

PSA: Probabilistic Safety Assessment

PROL: Power Reactor Operating License

S-294: CNSC Regulatory Standard – Probabilistic Safety Assessment for Nuclear Power Plants

Appendix "B" **Project Funding History**

$ 000's			All Existing and Planned Releases (incl contingency) Cumulative Values								
Release Type	Month	Year	2008	2009	2010	2011	2012	2013	2014	Later	Total
Partial	Jul	2008	1,800	10,200	10,400	4,400					26,800
											0
											0
											0
											0
											0
											0
											0
LTD Spent	Jul	2008	0								0

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

- Schedule is mandated by licensing requirements
- 1 Project Manager (Corporate) and 6 FTE's (Station Based) to support project over duration of the project
- Contract value based on budgetary estimates provided by vendors

Financial Assumptions:

- Annual cashflows dependant on resource availability, timeliness of contract award, vendor capability and mobilization.

Project / Station End of Life Assumptions:

Energy Price / Production Assumptions:

Operating Cost Assumptions:

Other Assumptions:

Probabilistic Safety Assessment 10 - 62440

Partial Release Business Case Summary N-BCS-03500-10000-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2007	This Release 2008	This Release 2009	Future Release 2010	Future Release 2011			Later	Total
Project Management (OPG)	-	100	200	200	100				600
Engineering & Drafting (OPG)	-	300	1,000	1,200	300				2,800
Material									-
Installation – PWU, BTU									-
Contract - Design									-
Contract - Installation									-
Contract - Analysis Services		[redacted]							
									-
									-
Interest (Capital Project Only)									-
Project Costs (excl contingency)	-	[redacted]							
General Contingency		[redacted]							
Specific Contingency									-
Project Costs (incl contingency)	-	1,800	10,200	10,400	4,400	-	-	-	26,800
2008-2012 Business Plan		-	-	-					-
Variance to Business Plan	-	1,500	9,200	9,400	3,900	-	-	-	24,000
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	[redacted]							
Total Release (incl contingency)	-	1,800	10,200	10,400	4,400	-	-	-	26,800
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate					
Design Complete	Zero to Minimal		Quality of Estimate	Conceptual + 60% to - 25%	
3rd Party Estimate	Yes	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor		Budgetary Quote(s)	Yes	Phase 1 Actual Used	No
Similar Projects		Contracts in place		Competitive Bid	

Variance to Business Plan

The estimated variance(s) to the 2008-2012 Business Plan will be addressed through the portfolio management process.
A PCRAF is not required

Reviewed By: Approved By:

P. Lawrence
Project Manager Date:

Y. Sirota
Manager, Reactor Safety Date:

Probabilistic Safety Assessment Upgrade 10 - 62440

Partial Release Business Case Summary N-BCS-03500-10000-R000

Attachment "B" **Project Variance Analysis**

OM&A	LTD	Partial Release		Variance	Comments
	N/A	Last BCS	This BCS		
	N/A	N/A	Jul		
		N/A	2008		
Project Management (OPG)				0	
Engineering & Drafting (OPG)				0	
Material				0	
Installation – PWU, BTU				0	
Contract - Design				0	
Contract - Installation				0	
Contract - Other				0	
				0	
				0	
Interest (Capital Project Only)				0	
Project Costs (excl contingency)	0	0	0	0	
General Contingency				0	
Specific Contingency				0	
Project Costs (incl contingency)	0	0	0	0	
Committed Cost				0	
Inventory Write Off Required				0	
Spare Parts / Inventory				0	
Total Release (incl contingency)	0	0	0	0	
Total Release (excl contingency)	0	0	0	0	
Ongoing OM&A (non-project)				0	
Removal Costs (incl in above)				0	

Comments:

As this is the first release for this project, the variance analysis is not applicable.

Attachment "C"

Key Milestones

Completion Date			Description
Day	Mth	Yr	
01	09	08	Initiating Events identified and frequency calculated.
30	09	08	Detailed PEP issued.
28	02	09	Event Tree analysis completed.
30	03	09	Screening analysis for low frequency external events completed.
31	06	09	Fault Tree analysis completed.
31	12	09	Level 1 Integration completed.
31	03	10	Level 1 fire PRA completed.
31	06	10	Seismic margin assessment completed.
31	06	10	Containment fault trees completed.
31	10	10	Level 2 PRA completed.

A Project Execution Plan (PEP) will be approved by September 2008.

Comments:

Calandria Tube Replacement Execution 13 - 40669 OM&A

Full Release Business Case Summary NK30-BCS-31230-00002-R000

1/ RECOMMENDATION:

We recommend a full release of $ 19.8 M (including contingency) for the execution of the Calandria Tube Replacement (CTR) on Unit 7 (Channel A13) at Pickering B in 2008. The full release will fund training and rehearsals on mockup, execution of CTR, post-requisite tasks including the transportation of removed components to AECL-CRL and subsequent tool and equipment decontamination, clean-up and storage.

Following a turbine trip on April 6th, 2008, unit 7 was placed in Guaranteed Shutdown State (GSS), by injecting gadolinium (poison) into the core to absorb neutrons. During this normal shutdown process, operators unexpectedly had to add more poison to maintain correct concentrations. Per procedure, the reactor was subsequently placed in a safe state by draining the moderator system and inserting all shutoff and control rods. An investigation has determined that additional gadolinium was required because the presence of CO_2 in the moderator.

Although a leak was first identified in 2005, the implications were not fully understood. An operating memo allowed unit 7 to continue operating with out-of-specification moderator chemistry and with higher action levels for moderator conductivity while analysis was undertaken. While much of the analysis has been competed, this recent outcome was unexpected. By procedure, we are not allowed to restart Unit 7 until we have by eliminated the ingress of CO_2 to the moderator.

Currently CT replacement at PNGS-B is not possible, mainly due to lack of a CT cutting tool, associated procedures, and required modifications to other tooling. These issues are currently being addressed by another project (Development of CT Replacement Capability – 49121) that was started in January 2008. Although current project scheduling calls for cutting tool readiness in September 2009, we will work with the supplier to accelerate the program in order to have the cutting tool available for July 12, 2008. This will allow for CTR completion in mid August and unit start up in September 2008. Cost estimates have been developed in detail based on previous experience with Pressure Tube Replacement. A $3.0M contingency has been included to mitigate the risk outlined in Section 6.

We will minimize overall outage time by moving forward work that is currently scheduled for a planned Unit 7 fall outage (P871), so that it can be completed in parallel with the CT Replacement. As a result, we do not expect that Unit 7 will require a planned outage in either 2008 or 2009.

$000's (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011	2012	Later	Total
Currently Released	None								-
Requested Now	Full		19,841						**19,841**
Future Funding Req'd	None								-
Total Project Costs		-	**19,841**	-	-	-	-	-	**19,841**
Other Costs									-
Ongoing Costs									-
Grand Total		-	**19,841**	-	-	-	-	-	**19,841**
Investment Type Sustaining		Class OM&A		NPV N/A		IRR N/A		Discounted Payback N/A	

Submitted By:

P. Tremblay
Senior Vice President, Pickering B

July 7, 2008
Date:

Finance Approval:

D. Hanbidge
S.V.P. and Chief Financial Officer

Date:

Line Approval (Per OAR Element 1.2 Project not in Budget):

J. Hankinson
President & Chief Executive Officer

24/07/08
Date:

2/ BACKGROUND & ISSUES

AGS Leak - Moderator & Moderator Cover Gas Operational Considerations

The annulus gas system (AGS) leak into the moderator has resulted in high conductivity/ low pH of the moderator, requiring increased frequency of resin slurrying, increased moderator cover gas purge, and increased monitoring of moderator chemistry parameters. This has resulted in increased waste generation, worker dose, and consumables. C-14 emissions have also increased. Although the C-14 emissions are below the regulatory Action Level of 340 Ci/week for the station, they are exceeding the Internal Investigation Level (IIL) of 3.4 Ci/ week. A third party review of the impact of continued operation with the current moderator chemistry regime on Calandria vessel internals and components was completed in February 2008 and concluded that the risk of hydrogen embrittlement and stress corrosion cracking is low.

Proposed Annulus Gas System (AGS) modification

An annulus gas system (AGS) modification to replace the existing carbon dioxide gas (CO2) with a mixture of CO2 and Helium (He) is being pursued for Unit 7. However, this modification would only mitigate the impact of the leak, and may not be sufficient in the long term. Even if the AGS modification is implemented, an increase in leak rate could result in allowable limits for moderator chemistry to be exceeded, and replacement of the leaking channel would still be required.

CT Replacement Capability

Currently, CT replacement at Pickering B is not possible, mainly due to lack of a CT cutting tool and associated procedures, and required modifications to other tooling. The longest-lead item for CT replacement capability is the design and build of a CT cutting tool, production of CT cutting tool procedures, and tool proving/mock-up testing. All other preparatory work identified can proceed in parallel.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

IMPACT $ M	Timing (2008)	Days	2008 Business Plan	2008 Estimate
Forced Outage (Unit 7) (Revenue)	06 Apr to 08 Sep	154	0	-80.2
Planned Fall Outage (Unit 7) (Revenue)	13 Oct to 04 Dec	52	-27.1	0.0
Total Revenue (based on 85% capacity factor)			-27.1	-80.2
49121 CT Capability (Capital)			0	-5.9
40667 CT Capability (OM&A)			0	-0.3
40669 CT Execution (OM&A)			0	-19.8
Total OM&A & Capital			0	-26.0
Grand Total (Cash Flow)			-27.1	-106.2

Status Quo - Not Recommended

Revenue losses will accumulate at approximately $521K per day until we can meet the criteria of zero CO2 ingress to the Moderator and bring Unit 7 back in service.

Alternative 1 - Replace Calandria Tube as quickly as possible - Recommended

There are no alternate repair strategies currently available that can reduce the ingress of CO2 to zero.

Accordingly, we recommend using all available resources to replace the Calandria Tube as quickly as possible.

This strategy includes the following:

- Advancing the delivery of the Calandria Tube Cutting Tool to July 12, 2008
- Reducing the critical path to its minimum
- Moving forward currently planned P871 outage work to be completed in parallel with CT Replacement

With revenue losses mounting at a rate of $521K per day, there is no financial advantage in delaying the repair. The revenue lost by delaying the CT replacement to the planned fall outage far outweighs any cost benefit generated by that strategy.

The above chart indicates the overall impact on Operations.

Alternative 3 – Alternate Repair Strategies - Not Recommended

There are no alternate repair strategies currently available that can the ingress of CO2 to zero.

4/ THE PROPOSAL

A full release of $ 19.8 M will provide funding for:

- Execution of PT and CT replacement of fuel channel A13 in Unit 7.
- Delivery of the removed fuel channel components to AECL-CRNL.
- Storage/disposal of the CT and PT at AECL-CRNL.

Cost estimates have been developed in detail based on previous experience with Pressure Tube Replacement. A $3.0M contingency has been included to mitigate the risk outlined in Section 6.

All other costs associated with the completion of P871 work during the forced outage will be charged to Outage costs.

5/ QUALITATIVE FACTORS

None

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
CTR is an infrequently performed activity.	Higher cost / extended schedule / revenue loss exceeds estimate	**Medium**	Include extra contingency	**Low**
A new tool set is being utilized for the first time on a Pickering B reactor.	Higher cost / extended schedule / revenue loss exceeds estimate	**Medium**	Include extra contingency	**Low**
Scope				
Execution window for CTR extends beyond plan.	Increased outage cost.	**Medium**	Quality of tool and procedure proving must be high. Early start required. Training and rehearsals must be effective with all required personnel present. Release of personnel must be timely.	**Low**
Schedule				
C/T Cutting tool Not Available. A 3rd C/T Flask is Required.	Delay in start of CTR.	**Medium**	Expedite purchase orders and delivery.	**Medium**
Modification packages for remaining tooling or tools that require fabrication do not arrive as planned.	Late start to tool proving and training of personnel.	**Medium**	Develop contingency plans for tool fabrication and delivery.	**Medium**
Maintenance configuration analysis documentation not provided in timely manner.	Feeder disconnect activity cannot proceed leading to overall schedule delays.	**Medium**	Early agreement on delivery schedule with EMD. Early start and completion of analysis.	**Low**
Resources				
CTR team members identified must be released to the CTR Project in a timely manner.	Delay in tooling/procedure development. Late start to training and rehearsals. Late start to CTR execution.	**High**	Identify staff early. Procure an Agreement from Base Organizations (majority with IMS)	**Medium**
A zone2/3 area within the fenced area to train and tool prove for SFCR & CTR.	Without this area the tool proving of contaminated tools cannot be performed. Potential delay in start of CTR if area not provided in expeditious manner.	**Medium**	Assign a station SPOC to investigate an area (120' X 50') to erect a zone2/3 area mock up and layout contaminated tooling. Areas being considered include PA Unit 2/3	**Low**

			turbine hall and UPP.	
Some of the clean C/T Tools belong to Bruce Power. They need to be borrowed or purchased by the CTR Project.	Delay in start of CTR as contaminated tooling will require modification. Training for use of the contaminated tools will require additional Zone 2/3 space.	**Low**	Develop an agreement with Bruce Power	**Low**
Technical				
Presently there is no capability to repair a damaged tube sheet in the rolled joint area. The postulated leak path is currently through one of the two rolled joints.	Extension to P871 outage to accommodate new tooling development and delivery.	**High**	Develop a sub team and perform a detailed assessment of the the risk and identify contingency tooling required.	**Medium**
				Low
Regulatory				
None				
Environmental				
None				
Health & Safety				
Highly efficient Shielding Strategy required due to high dose expected at working distance.	Increased level of dose uptake requiring increase in staffing numbers for reactor face work. Ultimately effects project cost.	**Medium**	Early development of a shielding strategy plan.	**Low**
Investment				
Leak is not from Channel A13	Significant revenue loss while determining source of the leak	**Medium**	Pressure holding test schedule to confirm A-13 is the leaking calandria tube (WO 01674432)	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	**Sep 2008**	**Mar 2009**	**IMS / C & E**

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	No indication of CO_2 ingress into the moderator	CO_2 ingress into the moderator system	Leak has stopped	Online dewpoint data	C&E
2.	Transfer of removed PT and CT components to Roadrunner for transport to AECL-CRNL. Storage/disposal of PT/CT at AECL-CRNL.	No shipment has been made	PT/CT is safely stored at AECL-CRNL	PT/CT is safely stored at AECL-CRNL	C&E
3.	Decontamination, inventory and storage of all CTR tooling and equipment after job completion	Decontamination has yet to be performed	All CTR tooling and equipment is decontaminated and stored after job completion	Dose measurements will be taken of CTR tooling and equipment to ensure they are of exceptable levels, storage space to be allocated	IMS

Appendix "A" Glossary (acronyms, codes, technical terms)

CT – Calandria Tube
PT – Pressure Tube
CTR – Calandria Tube (and pressure tube) Replacement
ALARA – As Low As Reasonably Achievable
QA – Quality Assurance
OEM – Original Equipment Manufacturer
C&E – Components and Equipment
IMS – Inspection Maintenance and Services

Appendix "B" Project Funding History

$ 000's OM&A Release Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Total
				All Existing and Planned Releases (incl contingency) Cumulative Values							
Full	Jun	2008		19,841							19,841
											0
											0
											0
											0
											0
											0
											0

LTD Spent	Jun	2008	0	0							0

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:

Project cost is based on Sponsor review, OPEX, budgetary quote, and lessons learned.
18% contingency ($3,050K)

Financial Assumptions:

Discount rate = 7%
Tax rate per Corporate guidelines

Project / Station End of Life Assumptions:

CT Replacement = August 2008
Project Completion = December 2008

Energy Price / Production Assumptions:

$49.50 MWH for 2008, then escalating at 2% per year
85% Capacity Factor applied
Unit 7 rating assumed at 516 MW

Operating Cost Assumptions:

Other Assumptions:

All costs not associated with Calandria Tube Capability and Execution will be charged to outage costs.

CT Replacement Execution 13 - 40669 OM&A
Full Release Business Case Summary NK30-BCS-31230-00002-R000

Attachment "A" **Project Cost Summary**

$000's OM&A	LTD Prior Yr 2007	This Release 2008	2009	2010	2011	2012	2013	Later	Total
Project Management (OPG)		734							**734**
Engineering & Drafting (OPG)		1,280							**1,280**
Material		1,650							**1,650**
Installation – PWU, BTU		9,567							**9,567**
Contract - Design									-
Contract - Installation									-
Contract - Augmented Staff		3,560							**3,560**
Storage of removed PT/CT									-
									-
Interest (Capital Project Only)									-
Project Costs (excl contingency)	-	**16,791**	-	-	-	-	-	-	**16,791**
General Contingency		3,050	-	-					**3,050**
Specific Contingency									-
Project Costs (incl contingency)	-	**19,841**	-	-	-	-	-	-	**19,841**
2008-2012 Business Plan		-	-	-	-				-
Variance to Business Plan	-	**16,791**	-	-	-	-	-	-	**16,791**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	-	**16,791**	-	-	-	-	-	-	**16,791**
Total Release (incl contingency)	-	**19,841**	-	-	-	-	-	-	**19,841**
Ongoing OM&A (non-project)									-
Removal Costs (incl in above)									-

Basis of Estimate

Design Complete	Zero to Minimal		Quality of Estimate	Budget +30%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	N/A
Similar Projects	Yes	Contracts in place	No	Competitive Bid	N/A

Variance to Business Plan

The estimated variance(s) to the 2008 – 2012 Business Plan will be addressed through the portfolio management process.

Reviewed By:

18 Jun 08

John Stopar
~~Project~~ Manager

Approved By:

June 18/08

Roy Brown
Eng & Mods Director (Strav V)

Attachment "B" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
31	May	08	Identify & Procure Material
12	Jul	08	Cutting Tool, CT Flask, other tooling available
18	Jul	08	Final CTR Challenge Meeting
26	Jul	08	Demonstrate Capability on Mock Up
03	Aug	08	Fuel Channel A13 Removed
20	Aug	08	Calandria Tube Replacment
24	Aug	08	Fuel Channel A13 installation
21	Nov	08	Tool Cleanup and Storage
21	Nov	08	Component Transfer
11	Dec	08	Project Closure

A Project Execution Plan (PEP) will be approved by May 2008

Comments:

Fuel Channel Life Management 10 - 62444

Partial Release Business Case Summary N - BCS - 31100 - 10001 – R000

1/ RECOMMENDATION:

We recommend a Partial Release of $12.3 Million OM&A for the Fuel Channel Life Management Project. A request for the remainder of the project cost (estimated at $12.7M) will be submitted in August 2010 when more certainty of the full scope and cost of the total project will be developed. This project is jointly funded between OPG and Bruce Power.

Fuel channel pressure tubes in most OPG CANDU units are beginning to approach their nominal operating life of 210k Equivalent Full Power Hours (EFPH). Accordingly, the prospect of multi-unit stations requiring refurbishment within a few years of each other is a growing concern because that would lead to competition for scarce re-tubing resources to support concurrent refurbishment operations. As a result, OPG is considering alternatives to achieve greater value from operating units and provide greater planning flexibility.

Moreover, due to the various degradation mechanisms related to fuel channels, the exact criteria for end-of-life or when fitness-for-service limits will be reached are not well defined. The methodologies, models and their bases currently used to demonstrate fuel channel fitness-for-service may not be adequate for late life assessments. In addition, there is an insufficient amount of inspection data and test results from ex-service pressure tube material on which to base projections. For these reasons, OPG fuel channel experts currently do not have a high level of confidence that the Darlington units can exceed 187k EFPH.

At this time, fuel channel R&D to support fitness-for-service is conducted through COG work packages which address the needs of all COG partners. However, if the pace of these COG activities is not accelerated and tailored to satisfy the specific objectives of OPG, the possible refurbishment start date of Darlington may need to be advanced to 2014 from the current planning scenario start date of 2016. As it takes more than 5 years to plan such a major undertaking, adequate lead time for a possible start date of 2014 would already be an issue.

The objective of this project is to have high confidence that Darlington can operate to 210k EFPH or beyond and that Pickering B can operate to 240k EFPH or beyond. This partial release will allow the critical path/long lead items to be initiated with the appropriate contractors to provide the results by 2012 which will subsequently support development of technical basis documents for continued fitness-for-service.

This project will accelerate some work being conducted through the CANDU Owners Group (COG) Research & Development (R&D) program as well as resolve issues which are outside of the general COG scope. The activities which will be initiated with this Partial Release includes the following key elements (to the end of 2010):

1. The first 1-1.5 years of a four year COG Joint Project with AECL and Bruce Power (BP) to conduct burst tests on ex-service pressure tubes to determine their fracture toughness at end-of-life (EOL) conditions;
2. Additional fracture toughness tests to support EOL limits
3. Defining annulus spacer surveillance requirements for subsequent testing/examination activities when pressure tubes and spacers are removed;
4. The first 1-1.5 years of 2 and 3 year experimental programs on pressure tube crack initiation to improve the basis for modifying the fitness-for-service methodologies and demonstrate increased margin to crack initiation.

$M (incl contingency)	Type	LTD 2008	2009	2010	2011	2012	2013	Later	Total
Currently Released	None								-
Requested Now	Partial		2,533	9,728					12,261
Future Funding Req'd	Full				7,741	4,010	908		12,659
Total Project Costs		-	2,533	9,728	7,741	4,010	908	-	24,920
Non Project Costs									-
Grand Total		-	2,533	9,728	7,741	4,010	908	-	24,920

Investment Type	Class	NPV	IRR	Discounted Payback
Value Enhancing	OM&A	2,198	N/A	N/A

Submitted By:

RCMa[illegible]

for W. Robbins
Chief Nuclear Officer

Date: 27 July 09

Finance Approval:

D. Hanbidge
SVP & Chief Financial Officer

Date:

Line Approval (Per OAR Element 1.2 Project not in Budget)

T. Mitchell
President & Chief Executive Officer

10 Aug. 2009
Date

2/ BACKGROUND & ISSUES

Although the life limiting pressure tube degradation mechanisms vary slightly between stations (See Project Charter), this can change over time and the degradation mechanisms listed below have an impact on pressure tubes at both Pickering B and Darlington.

This type of R&D work is typically eligible for Scientific R&D tax credit, and one will be pursued to reduce the overall cost to OPG.

Deuterium ingress and its impact on material properties

During hot operation, fuel channel pressure tubes react with the heavy water coolant and, as a consequence of this, the concentration of hydrogen (deuterium and protium quoted in terms of the equivalent hydrogen concentration, H_{eq}) increases over time. As well, in the pressure tube/end fitting rolled joint region, there is an additional galvanic corrosion component which makes the process in this region much more rapid. Since pressure tube material has a limited solubility of hydrogen which increases with increasing temperature, the brittle hydride phase is present during unit heat-up and cool-down transients - which makes fuel channel pressure tubes susceptible to an active cracking mechanism, delayed hydride cracking (DHC). As well, it is unknown whether the H_{eq} anticipated to be found later in fuel channel life will have an adverse impact on the mechanical properties of pressure tubes.

Due to the limited fracture toughness data available for high H_{eq} conditions, CSA N285.8 limits the allowable H_{eq} in the main body of a pressure tube (BOT) and in the tensile portion of the rolled joint (RJ) region to 70 ppm at the inlet and 100 ppm at the outlet. These values are therefore referred to as "End-of-Life" (EOL) limits. Although these are currently hard limits, operation below this value (but above the solubility limit) cannot be supported with the available data.

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 ($H_{initial}$) values in any CANDU units. Other contributing factors include a scarcity of rolled joint H_{eq} data and the 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. As it takes more than 5 years to organize for such a major undertaking, adequate lead time to start in 2014 is already an issue (as illustrated in Attachment D). In addition, there is a significant loss in economic value if the Darlington units need to be refurbished earlier. 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 H_{eq} above the solubility limit and beyond.

Until recently, Pickering B was not expected to exceed the EOL 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 the H_{eq} exceeds the solubility limit at both inlet and outlet rolled joint burnish marks.

Although the fuel channel work conducted under COG is considerable, if it continues at its current pace, it will not address the following concerns in time for OPG to make confident predictions of fuel channel pressure tube life in order to optimally plan potential refurbishment activities:

a) Pressure tube material property changes with high H_{eq};
b) Kinetics of deuterium ingress (increasing H_{eq}) in the rolled joint region - to project future values and predict when EOL values will be reached; and
c) The appropriateness of the current limits

If it is demonstrated that there remains an adequate margin on material properties with high H_{eq}, changing the limits may be justified, thereby increasing confidence that Darlington can operate to 210k EFPH or beyond and that Pickering B can operate to 240k EFPH or beyond.

Crack Initiation

Extensive flaw populations in Pickering B were generated in pressure tubes, largely during commissioning due to construction debris entrained in the Primary Heat Transport System (PHTS). Flaws that fail to satisfy the acceptance criteria provided in CSA N285.4-05 must be evaluated for acceptability and the condition must be dispositioned with the regulator. CSA N285.8-05 provides the recognized and accepted means of assessing flaws. One requirement is to demonstrate that crack initiation will not occur from DHC, fatigue and hydrided region overload. Pickering B currently has a number of flaws where crack initiation is predicted. This has resulted in the imposition of thermal cycle limits on operation and a requirement for re-inspection to assure that there has been no crack propagation. Although crack initiation has never been observed, these flaws continue to be monitored with a decreasing number of available cycles due to increasing deuterium concentration in the pressure tubes. Procedures currently used to assess flaws carry a significant degree of conservatism which is becoming increasingly limiting.

Test programs are underway to address the excessive conservatism involving the use of more realistic flaw geometries, H_{eq} and sample conditioning. Initial results have shown much greater resistance to crack initiation in pressure tubes using these conditions. However, it is proceeding at a pace that will not produce the desired results by 2012 as required by OPG to better plan possible refurbishment activities.

A recent attempt to modify the evaluation procedure for fatigue crack initiation was not accepted by the CNSC because there was insufficient data to support the proposed changes. Following this, an 'interim approach' was adopted with a commitment to produce more data in the next few years to support the original request. This would include testing pressure tube material in air and reactor water (to capture any environmental effects).

Additional testing to support changes to all crack initiation mechanism evaluation procedures would increase the operating window (especially for Pickering B) by showing that pressure tubes currently in service have a higher resistance to crack initiation than they are currently given credit for in assessments.

Probabilistic Core Assessments and Leak-Before-Break

CSA N285.8-05 requires that probabilistic core assessments be conducted to demonstrate that the probability of pressure tube rupture remains acceptably low, and that leak-before-break capability remains.

In addition to evaluating detected flaws found during inspections, the condition and acceptability of the pressure tubes in the reactor core as a whole must be evaluated using a Probabilistic Core Assessment (PCA). Among other input information, data from crack initiation experiments and the subsequent evaluation methodologies in the PCAs which impact on the probability of pressure tube rupture are to be evaluated against an acceptance criterion. The current state-of-the-art understanding of crack initiation is not captured in the current PCA code and, for this reason, the results are considered to be conservative. As well, the tool is not qualified to the industry standard of CSA N286.7. This exposes OPG to some regulatory risk.

Leak-before-break refers to the scenario where a through-wall crack in a pressure tube results in a leak into the Annulus Gas System which is detected and subsequent operator actions are taken to place the reactor in the cold and depressurized state prior to reaching the extent of crack propagation when pressure tube would catastrophically fail. Assurance of this capability is becoming increasingly difficult as the pressure tube properties degrade with time, and a change in methodology and/or input parameters can have a significant impact on the eroding margin between what is done at the stations and what needs to be done to demonstrate compliance.

Spacer Integrity and PT/CT Contact

Annulus spacers perform the critical function of maintaining a gap between the pressure tube and calandria tube – to assure that contact between these components cannot occur. This contact led to the catastrophic failure of channel G16 of Pickering Unit 2 in 1983. As such, spacer integrity must be demonstrated over the full operating life of the reactor.

The spacers used in Darlington are a tight-fitting design made from Inconel X-750 design which is meant to remain in its as-left position for the duration of the operating life. Recent OPEX from the recent removal of the pressure tube and spacers from channel O18 in Darlington Unit 2 has indicated that the structural integrity of this spacer design may not be sufficient to achieve the current nominal operating life of 210k EFPH. This is because the removed spacers arrived at AECL-CRL (Chalk River Laboratories) in several pieces and testing indicated that some material properties had degraded. Although the flasking and transportation to AECL-CRL may have led to the ultimate failure of these spacers, their degraded properties are due to operation. It is unknown at this time whether the degradation in properties of spacers in service at Darlington has saturated or if degradation will continue. This issue is one that could result in premature shutdown of Darlington units, since failure of a spacer leading to pressure tube-calandria tube (PT-CT) contact in the outlet region of almost any pressure tube in Darlington would result in hydride blister formation and subsequent pressure tube rupture.

Although the material properties of the loose-fitting Zr-Nb-Cu spacers in Pickering B are considered to be adequate for a 240k EFPH pressure tube life, the root cause investigation of the failed calandria tube in Pickering Unit 7 channel A13 revealed significant spacer wear as well as wear on the adjacent pressure tube and calandria tube surfaces. This calls into question whether the spacers in Pickering B are capable of maintaining a PT-CT gap during a 240k EFPH pressure tube. The root cause investigation team has produced an interim report, but the current funding source will not support additional activities to determine the root cause of spacer wear, the extent/severity of spacer is in OPG reactors, or the impact of worn spacers on PT-CT contact predictions.

In addition, there is currently no program to periodically assess spacer integrity as they can only be examined when a fuel channel pressure tube is replaced. Moreover, they aren't part of the normal surveillance activities associated with fuel channel replacement. Therefore, a spacer program is needed to assure structural integrity over the full unit operating life. Elements of this program include: a comprehensive literature survey to determine the credible degradation mechanisms and subsequent assessment methods/procedure and acceptance criteria for the results.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions EFPH 000's	Timing	Base Case			Recommendation		
		DNGS	PNGSB	Total	DNGS	PNGSB	Total
		187K EFPH	210K EFPH		210K EFPH	240 EFPH	
Revenue	2009 to EOL	120,551	6,513	127,064	131,831	12,198	144,029
OM&A Operations	2009 to EOL	(54,964)	(4,341)	(59,305)	(59,321)	(7,672)	(66,993)
OM&A Project	2009 to EOL	0	0	0	(12)	(12)	(25)
Refurb (Capital)	2009 to EOL	(5,827)	0	(5,827)	(6,051)	0	(6,051)
Present Value (PV)	2009 to EOL	9,053	1,261	10,314	10,321	2,191	12,512
Net Present Value (NPV)		**N/A**	**N/A**	**N/A**	**1,268**	**930**	**2,198**

Base Case: Not Recommended - Continue with current COG R&D program to support Fuel Channel FFS (Do nothing)

At the pace with which fuel channel R&D is proceeding under COG, the results of testing and associated analyses will be not be completed in time to demonstrate high confidence (>70%) in fitness-for-service beyond 187k EFPH for Darlington and beyond 210k EFPH for Pickering B. This could result in Darlington units reaching their end-of-life as early as 187k EFPH with the possible refurbishment advanced from 2016 to 2014 - at substantial cost. For Pickering B, support for the technical basis for operation of fuel channel components to 240k EFPH will likely not have the required confidence by 2012 if the work is not accelerated.

Alt. 1: Recommended - Follow proposed plan to acquire appropriate information for 2012 (Do this)

Completing the proposed experimental and analysis work within the required timeframe in conjunction with executing LCM planned inspections and maintenance will demonstrate whether there is high confidence (>70%) that Darlington units can operate to 201k EFPH or beyond and Pickering B can operate to 240k EFPH or beyond – allowing possible refurbishment activities to be planned effectively at Darlington. The operation of Pickering B to 240k EFPH would realize greater economic value from these units.

Alt. 2: Not Recommended - Delay proposed work by one year

If the proposed work is delayed by one year, the required results to support high confidence nominal EOL predictions will not be realized until 2013. This is one year later than the target date and only one year before possible Darlington refurbishments would have to begin if operation beyond 187k EFPH cannot be supported with high confidence (>70%), leaving no adequate lead time to plan the refurbishment.

Note: Regulatory conditions require that at least some of this work is funded and initiated in the short term (i.e. fatigue crack initiation experiments).

Alt. 3: Not Recommended - Conduct some of the work proposed (Do less)

This alternative is a 20% cost reduction in scope over the recommended Alternative 1 where the work with the least impact on satisfying the project objective was removed from the scope. It is anticipated that the impact of reducing the scope would result in a reduction to the confidence to below 70% in EOL predictions required to support operation of Darlington to 210k EFPH and Pickering B to 240k EFPH.

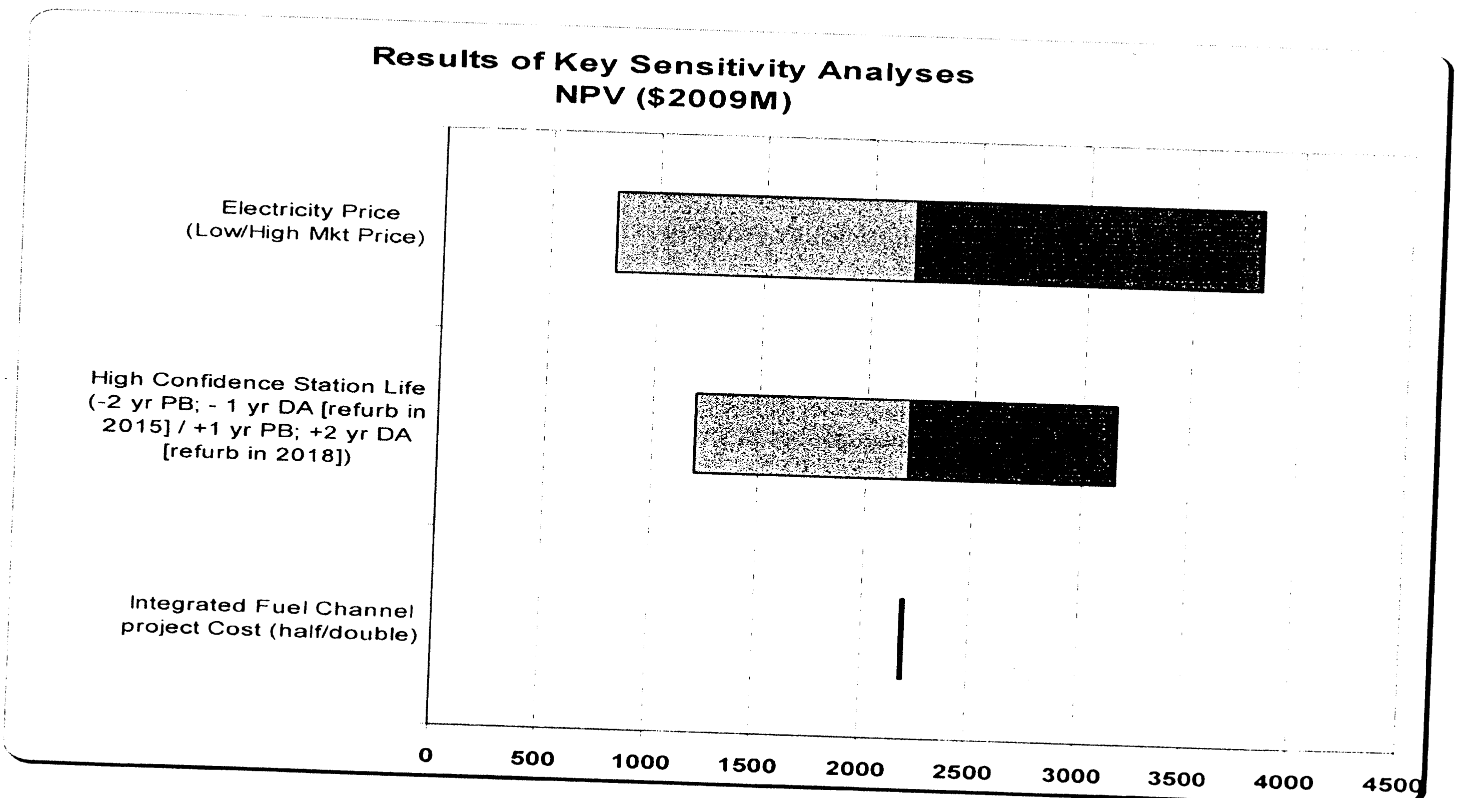
This alternative is not recommended based on supporting high confidence (>70%) projections of operating Darlington units to 210k EFPH or beyond (from 187k EFPH) and Pickering B units to 240k EFPH or beyond (from 210k EFPH), the calculated value of this work exceeds the estimated cost and any reductions to the scope could impose an unacceptably large risk on the project and impede achievement of objectives.

Alt 4: Not Recommended - Request regulatory relief on life limiting issues

In the area of fuel channel fitness-for-service, several submissions to revise the fitness-for-service methodologies (or inputs to these methodologies) have not been completely accepted by the regulator and 'interim approaches' have been utilized which include commitments to conduct additional work to justify the original submissions. By requesting relief in areas where commitments have been given (including some cases with formal plans) to justify previous submissions, the regulator may lose confidence in OPG since the regulator may already consider the 'interim approaches' to be a form of relief. Moreover, technical experts in the industry share most of the concerns of the regulator, and it would be prudent to get the appropriate answers rather than requesting relief.

Alt. 5: Not Recommended - Accelerate program further to get answers in 2011 (Do more)

Although having answers sooner (i.e. 2011) would be very beneficial, it is unlikely that additional funds would make this possible. The current limitation in this work is resources – specifically technical experts, technicians and facilities. Even if the funding could be made available immediately, facilities similar to those at AECL-CRL, capable of conducting work on pressure tubes, cannot be built in the time required.



Results of the economic assessment were tested for sensitivity to key inputs such as (i) assumed electricity price, (ii) length of additonal station life achieved, and (iii) integrated fuel channel project costs, and indicate the following:

(i) The value is extremely sensitive to the assumed electricity price. In a high price regime, the value would be $3.8 B and in a low price regime, the value would be $800 M. A low price regime would result from low electricity demand and low gas prices, such as during a prolonged economic slowdown or high conservation.

(ii) The value is sensitive to the station life that can be achieved with high confidence. If Pickering B units achieve only 225k EFPH and Darlington units achieve only 200k EFPH with Darlington refurbishment starting in 2015, then the value would be $1.2 B. If the Pickering B units achieve 248k EFPH and the Darlington units achieve 225k EFPH with Darlington refurbishment starting in 2018, then the value would be $3.1 B.

(iii) The value is insensitive to project costs even if they are doubled.

4/ THE PROPOSAL

This Partial Release is to start critical path/long lead time work required to increase confidence that Darlington units will operate to 210k EFPH or beyond and that Pickering B units will operate to 240k EFPH or beyond. It is intended that this program will provide the results by 2012 thereby allowing development of the appropriate bases to support fitness-for-service. The partial release will fund the project work to be conducted until the end of 2010.

The scope of work for the complete project includes activities to address:

1. Deuterium ingress and its impact on material properties
2. Crack initiation
3. Leak Before Break and Core Assessments
4. Spacer Integrity and PT/CT contact

Tasks under each category are designed to create a more comprehensive, overall understanding of fuel channel degradation and fitness-for-service limits. This work will support regulatory submissions to modify fitness-for-service methodologies, acceptance criteria, etc. related to fuel channels. This would essentially shift the fitness-for-service limits and (ideally) support the operation of Pickering B units to 240k EFPH or beyond and the operation of Darlington to 210k EFPH or beyond.

The following work includes the total current project work scope to be conducted over the next 3 years as a joint project between OPG and Bruce Power with cost sharing at a ratio of 5.5:3.5 (OPG:BP).

Deuterium Ingress and its Impact on Material Properties
A method will be developed to add hydrogen/deuterium to ex-service pressure tube material in a manner which does not affect the irradiation damage*. After this technique is qualified, tests to determine the fracture toughness at proposed end-of-life conditions will be conducted as proposed in the COG Joint Project 4299. Since it is anticipated that the engineering/qualification of a new method/technique will require approximately one year of effort and to mitigate the risk of a new technique not being capable of achieving the desired results, a parallel task involving the current technique will be pursued with a plan for its implementation as a non-ideal solution. Other, supplementary fracture toughness tests on both ex-service and un-irradiated pressure tube material will be conducted to support the development of fracture toughness curves at end-of-life H_{eq} levels.

Other activities to support deuterium ingress projections will be conducted including: developing detailed requirements for rolled joint H_{eq} model to ensure that the modification of current code addresses concerns over the lack of predictability; updating the body-of-tube deuterium ingress model to improve the accuracy of long term predictions; and using existing and new data/models to calculate the time reach end-of-life H_{eq} values for all units.

** This work currently carries the greatest degree of uncertainty/risk because the vendor(s) have not stated conclusively whether or not they can conduct some of the proposed work in their hot cells. Because of this, a parallel path of doing the engineering and initial qualification in other hot cell facility will be followed.*

Spacer Integrity and PT/CT contact
To address concerns over tight-fitting (Darlington) spacer integrity, the major scope of work includes: determination of the mechanism of degradation of I-X750 spacer material, development of a comprehensive program of condition monitoring including evaluation methods and acceptance criteria for examination of ex-service spacers and pursuing the implementation of PT-CT gap measurements to assure spacer integrity and capability to maintain an appropriate gap. As well, an experimental program to irradiate I-X750 may be warranted to determine the rate of degradation in early life for extrapolation and projection to late life operation.

To address the concerns over loose-fitting (Pickering B) spacer wear, the major scope of work includes: completing the root cause investigation for P7 A13, determination of the impact of spacer wear on PT-CT predictions, and examination of other available ex-service spacers to determine the possible extent of spacer wear in OPG reactors.

Crack initiation
Tests using more realistic sample geometries and conditioning cycles will be conducted to quantify increased crack initiation resistance. This will allow flaws in Pickering to pass fitness-for-service evaluations in the future as well as support Probabilistic Core Assessments.

The work includes: quantifying the positive benefit of reduced pressure shut down on crack initiation, increasing the variability and H_{eq} validity range on the non-ratcheting factor, determining the effect of having surface flaws and angled flaws versus full-length/axial flaws. Preliminary assessments of this type of work has indicated that pressure tubes are more resistant to crack initiation than current methodologies credit and, with the data to be acquired from these tests, the technical basis to modify fitness-for-service methodologies can be made.

Fatigue crack initiation experiments will be conducted in air on both ex-service material and un-irradiated material, as well as in a reactor water environment on un-irradiated material to support regulatory commitments to use the current 'interim approach' and make subsequent changes to the evaluation procedures. This will enable Pickering B to pass flaw evaluations and remove cycle limitations imposed by fatigue crack initiation.

Probabilistic Core Assessments and Leak-Before-Break

The Probabilistic Core Assessment tool will be updated to reflect the current understanding of fuel channel degradation, as determined by other parts of this project, to offer a more realistic assessment of reactor core integrity. In addition, the tool will be qualified to the requirements of CSA N286.7 as an Industry Standard Tool (IST).

A new approach to the leak-before-break methodology will be explored which follows what is done in US plants to move away from the overly conservative treatment currently used. This will enable increased margin to be demonstrated in assessments. This increased margin will allow further material degradation and equipment availability issues to be accommodated more easily.

The project work will also include ensuring that condition monitoring prescribed in the OPG Fuel Channel Aging and Life Cycle Management Strategy and Plan is executed. The resultant data is essential to determine when fitness-for-service limits will be reached. In addition, it is essential that experimental results be analyzed and technical basis documents developed to support improved methodologies meeting technical and regulatory requirements.

5/ QUALITATIVE FACTORS

This work is intended to be part of an industry-wide initiative to gain greater certainty on the fitness-for-service limits for fuel channels. If this is executed as a COG Joint Project, it gives Bruce Power important information concerning the timing of possible OPG refurbishment activities. This will help the industry to optimize refurbishment plans, and may reduce the strain on resources to conduct refurbishment of many units in parallel.

Even if it is determined that the current base case is accurate, and refurbishment activities must be brought forward in time from 2016 to 2014, this will be much more advantageous than unplanned shutdown of the units.

This work is part of a comprehensive Fuel Channel Life Management Plan which has been developed to drive to higher levels of confidence in longer pressure tube lives for the OPG nuclear units. Achieving higher levels of confidence has many benefits which are not easy to quantify including providing enhanced flexibility to OPG to:

(i) Manage the lead time constraints, and other preparatory issues (e.g. resource constraints, long lead time material, project mobilization) associated with the Pickering B refurbishment, should it proceed;
(ii) Manage the overall refurbishment schedule for the nuclear units, particularly the uncertainty around the refurbishment schedule for the Darlington units given current uncertainties in unit end-of-life dates, should it proceed;
(iii) Manage the uncertainties created by any potential delays to new nuclear in-service dates; and
(iv) Manage the potential significant capital and resource requirements and financial sustainability of OPG associated with multiple simultaneous refurbishments and new build nuclear campaigns;
(v) Manage regulatory risks associated with fitness-for-service limits.

6/ RISKS (see Attachment D for details)

		Low = 1 to 3	Medium = 4 to 9		High = 10 to 25	
		Impact				
		1	2	3	4	5
Probability	5	5	10	15	20	25
	4	4	8	12	16	20
	3	3	6	9	12	15
	2	2	4	6	8	10
	1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation (Probability x Impact): Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
Resources unavailable to do the work in the required timeframe	Get estimates and resource commitments from vendors before full release. Close collaboration with the COG fuel channel work program to ensure optimum utilization of existing resources. Pursue alternate facility for engineering work associated with new hydrogen addition technique. Spread work over multiple facilities with ability to scale up work at alternate facility.		12							**12**		8							**8**
Results indicate degraded properties which impact on continued operations (including other stations)	Pre-establish performance criteria and evaluate impact Monitor results progressively with hold points to ensure that expected performance attained and potential impact. Establish more comprehensive fitness-for-service assessments	10			10	10				**10**	4			4	4				**4**
Funding not available in time to complete work	Establish schedule based on release of funds and accelerate work if necessary and possible		15							**15**		8							**8**
Other EOL work not funded - negating large benefit of this work	Hold challenge meeting with OPG and industry partners to minimize probability of unfunded work.		10							**10**		5							**5**
Regulator disallows use of the results in determination of end-of-life limits.	Obtain buy-in from regulator on project plan and approach to be undertaken				6	12				**12**				2	3				**3**

BUSINESS CASE SUMMARY

	Low = 1 to 3	Medium = 4 to 9		High = 10 to 25	
	Impact				
Probability	1	2	3	4	5
5	5	[illegible]	[illegible]	[illegible]	[illegible]
4	4	8	[illegible]	[illegible]	[illegible]
3	3	6	9	[illegible]	[illegible]
2	2	4	6	8	10
1	1	2	3	4	5

Risk Description	Mitigating Activities	Before Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)	After Mitigation – Probability x Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environment	Nuclear Safety	Risk Rating (1 to 25)
	Keep the regulator informed of results as project progresses.																		
Unable to hydride material to appropriate levels with new technique	Parallel work to use current technique to get necessary data		8							**8**		4							**8**
FC LCM planned work not completed during outages to obtain necessary data	Ensure stations are aware of the impact of not conducting inspection work in LCM				12	12				**12**				4	4				**4**
Results from inspections show increased D-uptake rate in RJ	Use this work as basis, if possible, for increasing EOL limits	10				8				**10**	6				4				**6**
Vendor resists using new hydriding technique in hot cells	Pursue alternate facility for engineering work associated with new hydriding technique		9							**9**		4							**4**
Irradiated spacer properties indicate that properties are continuing to degrade	More comprehensive assessments will be conducted to demonstrate fitness-for-service	9					12			**12**	6				6				**6**
Unanticipated event causes hot cell unavailability	Allow enough lead time in work to absorb some delay		8							**8**		4							**4**
Bruce Power and/or Atomic Energy of Canada chooses not to co-fund this work in subsequent years	Contingency added in out years to accommodate any reductions in funding by other participants Additional OPG funding may be necessary to complete defined scope	8				8				**8**	4				4				**4**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2013	Jun 2014	VP, Science and Technology Development Division

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Results received from experiments and analyses	2016 assuming COG funding remains at current level, and appropriate task funded.	August 2012	Date final results are received to support next parameter	Manager, MCED
2.	Submission of technical basis to modify FFS to regulator	2016 based on appropriate results (see Item 1)	December 2012	Date of submission of documents to the regulator	Project Sponsor
3.	High confidence EOL predictions for Pickering B Fuel Channels	210K EFPH	240K EFPH	Fuel Channel experts concur with high confidence	Manager, MCED
4.	High confidence EOL predictions for Darlington Fuel Channels	187K EFPH	210K EFPH	Fuel Channel experts concur with high confidence	Manager, MCED

Appendix "A" Glossary (acronyms, codes, technical terms)

EOL – End-of-life – Based on design life of 210k EFPH
H_{eq} – equivalent hydrogen concentration if all deuterium [D] were replaced with protium [H] (H_{eq} = [H] + [D]/2)
D-ingress – with hot operation, deuterium enters pressure tube material
Hydriding – the process of adding hydrogen (deuterium or protium) to pressure tube material to simulate later life conditions
RJ – rolled joint between the pressure tube and end fitting
PT – Pressure tube
CT – Calandria tube
PHTS – Primary Heat Transport System
COG – CANDU Owners Group
PCA – Probabilistic Core Assessment, used to evaluate degradation of all fuel channels based on established methodologies and inspection results
CNSC – Canadian Nuclear Safety Commission, Canadian regulator under the Nuclear Safety and Control Act
AECL – Atomic Energy of Canada Limited
AECL–CRL – Chalk River Laboratories of AECL where ex-service fuel channel examination and testing is typically conducted

Appendix "B" Project Funding History

$ 000's		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2009	2010	2011	2012	2013	2014	2015	Later	Total
Partial	Jun	2009	2,533	9,728							12,261
Full	Aug	2010			7,741	4,009	908				12,658
											0
											0
											0
											0

Comments:

Appendix "C"

Financial Model – Assumptions

Financial Assumptions:

Discount Rate	7%	Cost Escalation (yr)	2%	SR & D Opportunity	See Comments
Progress Payments	N/A	Foreign Currency	???	Retainer Fee	???
Income Tax Rate		PST	???	Interest Rate (Capital)	???
Depreciation Rate (Capital)	N/A	Leasing	???	Indexed Priced Contract	???

Comments:
SR&D opportunity to be explored. It is likely that at least some of this work would qualify.

Project Cost Estimate:

Design Complete	N/A	Quality of Estimate	Budget + 30% to - 15%	3rd Party Estimate	N/A
Reviewed by Sponsor	Yes	OPEX used	N/A	Lessons Learned	none available
Similar Projects	Yes	Budgetary Quote(s)	No	First Unit Actual Used	Not unitized
Cost Sharing	TBD	Contracts in place	Some in place	Competitive Bid	None requested
Fixed Price Contract		Fee for Service	N/A	Firm Vendor Proposal	No

Comments:
Partner through COG and the CANDU industry will be sought to reduce costs to OPG.

Rationale for Cost Classification:

N/A

Generation Plan Assumptions:

Station	Unit	EOL		MW	Capacity	Planned Outages for Project Work (eg P1071)						
Pickering A	1	N/A	N/A		N/A							
	4	N/A	N/A									
Pickering B	5	N/A	N/A	N/A	N/A							
	6	N/A	N/A									
	7	N/A	N/A									
	8	N/A	N/A									
Darlington	1	Jun	2018	935	88%							
	2	Sep	2016									
	3	Mar	2020									
	4	Dec	2021									

Comments:
N/A

Fuel Channel Life Management 10 - 62444
Partial Release Business Case Summary N - BCS - 31100 - 10001 – R000

Attachment "A"

Project Cost Summary

	$000's OM&A	LTD 2009	2010	2011	2012	2013	2014	2015	Later	Total
Scores Basis	Project Mgmnt & Support	302	416	416	416	208				1,758
	Engineering	300	[redacted]							
	Procurement									-
	Construction									-
	Other									-
	Project R&D	1,866	[redacted]							
	Issue Management System	65								65
										-
										-
	Interest (Capital Project Only)									-
	Project Costs	**2,533**	[redacted]							
	General Contingency	-	[redacted]							
	Specific Contingency									-
	Project Costs	**2,533**	**9,728**	**7,741**	**4,010**	**908**	-	-	-	**24,920**
Cash	**Adjust to Cash Basis +/-**								-	-
	Project Costs	**2,533**	**9,728**	**7,741**	**4,010**	**908**	-	-	-	**24,920**
Funding	**Currently Released**									-
	This Release	2,533	9,728							12,261
	Future Release			7,741	4,010	908			-	12,659
	Project Funding	**2,533**	**9,728**	**7,741**	**4,010**	**908**	-	-	-	**24,920**

Note: Scores Basis = Cash Basis = Funding Basis (Timing differences only)

Budget										-
	Variance to Business Plan	**2,533**	**7,553**	**6,336**	**3,351**	**783**	-	-	-	**20,556**
Other	Removal Costs included above									-
	Inventory to be written off									-
	Spare Parts in Inventory									-

The estimated variance(s) to the **2009-2013 Business Plan** will be addressed through the portfolio management process.
A PCRAF **will be approved by** Oct 2009.

Reviewed By: [signature]
Norman Webb
Project Manager

June 11/09
Date:

Approved By: [signature]
Don Wilson
Strat IV Manager

2009-06-17
Date:

Attachment "B"

Milestones and In Service Declarations

Key Milestones

Completion Date			Description
Day	Mth	Yr	
31	May	2009	List of prioritized work with cost and schedule estimates developed
30	June	2009	BCS approval from AISC
31	Aug	2009	Funding secured for Long Lead items from Partial Release
31	Aug	2009	Issue RFP/RFQs for long lead work identified in plan
15	Sep	2009	Kick-off Meeting
30	Oct	2009	PEP issued for use
30	Jun	2010	BCS finalized with more accurate scope and cost estimates
31	Aug	2010	Approval of funding for project (BCS approved)
31	Aug	2010	Issue RFP/RFQs for balance of work identified in plan
31	Aug	2012	Results obtained from analysis and experiments
31	Dec	2012	Regulatory acceptance of the fitness-for-service basis for continued operation

A Project Execution Plan (PEP) **will be approved by Oct 2009**

In Service Declarations: (Capital Only)

Month	Year	Description	$ 000's	%

Attachment "C"

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 1000	About 1 in 100	About 1 in 10	About 1 in 5	>= 3 in 4
Rank	1	2	3	4	5

Risk Impact Chart

Impact Rating	Financial	Project Schedule (12 months)	Quality	Corporate Reputation	Regulatory / Legal	Health & Safety	Environment	Nuclear Safety
5	>80% of Total Project $	> 90 day delay	Significant, unacceptable non-conformance requiring extensive rework	National and international adverse coverage or impacts	Non-compliance with potential for significant implications for personnel, potentially large damages or Criminal Charges **OR** Potential loss of operating licenses	Potential for fatality(s)	Spill or release causing immediate and extended impact with off-site impacts, e.g.: Clean-up costs > $15M Cat. A spill (>55 pts)	Loss or serious degradation of a safety system
4	30% - 80% of Total Project $	30 - 90 day delay	Unacceptable non-conformance requiring some rework, but not major	Long-term local or national impact	Legislative non-compliance with potential for fines, charges, and damages **OR** Major degradation of reputation with regulatory bodies	Potential for life-threatening critical injury or permanent total disability, including occupational disease	Exceedances resulting in charges or Director's Order Cat. A spill (45 - 55 pts) Public complaints with OPG implications Explosion and/or major fire	Reduced effectiveness of a safety system
3	15% - 30% of Total Project $	10 - 30 day delay	Non-conformance bordering design tolerances, potential to require rework	Major local impact or minor national impact. Minor local damage	Systematic non-compliance with potential for fines OR Potential to cause strained relationship with regulator, increased surveillance and/or regulations	Potential for less serious critical injuries (e.g. fractures), permanent partial disabilities and temporary total disabilities of a significant nature	Cat. B spills Emission in exceedance of regulatory or legal limits Field orders or AMP's Public complaints with OPG implications Danger to health, life, or property	Reduced effectiveness of redundant safety system components
2	5% - 15% of Total Project $	3 - 10 day delay	Acceptable non-conformance, within design tolerances, no rework required	Complaints from local officials / politicians	Systematic non-compliance with impacts to project schedule OR Possibility of regulatory / legal implications	Potential for less serious temporary disabilities and injuries requiring off-site medical attention other than first-aid. Complete recovery by worker.	Cat. C spills - reportable Administrative infractions Public Complaints with plant level implications	Impact on a safety support or safety related system
1	<5% of Total Project $	< 3 day delay	Minimal impact on quality Routine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-compliance OR Routine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker.	Administrative, non-reportable events Cat. C spills non-reportable and spills resulting from Acts of God	

Numbers may not add due to rounding.

Table 1
OM&A Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects >$10M Total Project Cost[1]

Line No.	Facility	Project Name	Project Title	Category	Start Date	Final In-Service Date	Total Project Cost (M$) (Note 2)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M) (Note 3)	2007 Actual ($M)	2008 Actual ($M)	2009 Actual ($M)	2010 Budget ($M)	2011 Plan ($M)	2012 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		ONGOING PROJECTS FROM EB-2007-0905														
1	DN	Environmentally-Qualified Component Replacement	38457	Regulatory	Oct-04	Nov-10	63.1		63.1		12.2	16.7	9.3	6.7	0.6	0.0
2	PA	Replace Locking Tabs on Boiler Divider Plate (P1,P4)	49248	Sustaining	Jun-07	Jun-11	17.7	1.0			0.1	0.1	0.2	0.4	7.3	7.3
3	PA	P2/P3 Isolation Project	Various	Sustaining	Aug-05	Dec-10	67.1		67.1		9.5	13.5	22.5	20.6	0.0	0.0
4	PB	Steam Generator Water Lancing	40645	Sustaining	Apr-07	Dec-10	25.0		25.0		1.3	3.5	9.0	5.6	0.3	0.0
5	PB	Boiler Tab & Divider Plate Repair (P7 & P8)	40641	Sustaining	Feb-07	May-11	20.5		20.5		0.4	7.8	0.4	9.3	0.2	0.0
6	ENG	Digital Control Computer Aging Management	62553	Sustaining	Mar-04	Dec-12	14.5		14.5		0.7	2.4	0.6	1.0	2.4	1.9
7	ENG	Inspection Qualification	66105	Sustaining	Oct-06	Nov-12	10.5	4.1			0.3	1.0	1.3	1.3	1.2	1.1
8	ENG	Feeder Repair by Weld Overlay Proof of Concept	62435	Value Enhancing	Feb-05	Apr-10	17.5		17.5		0.5	1.5	6.9	0.0	0.0	0.0
9		**Subtotal**					**235.9**									
		COMPLETED PROJECTS FROM EB-2007-0905														
10	DN	Boiler Primary Side Cleaning	38296	Sustaining	May-01	Nov-08	24.2	24.7			0.1	0.0	0.0	0.0	0.0	0.0
11		**Subtotal**					**24.2**									
		CANCELLED/DEFERRED FROM EB-2007-0905														
12	DN	Boiler Primary Side Cleaning (follow-up to 38296)	38935	Sustaining	Jun-08	Deferred	1.7	2.1			0.0	0.9	0.8	0.0	0.0	0.0
13	PA	Unit 4 Boiler Flushing	49204	Regulatory	Jul-03	Cancelled	9.9		12.8		0.3	0.0	0.0	0.0	0.0	0.0
14	PA	Unit 4 Boiler Chemical Clean	49201	Regulatory	Jul-03	Cancelled	22.2		55.3		2.2	0.3	0.2	0.0	0.0	0.0
15		**Subtotal**					**33.8**									
		PROJECTS NOT IN EB-2007-0905														
16	NPT	Fire Safety Assessment Upgrade	26003	Regulatory	Aug-09	Dec-11	12.3	9.4			0.0	0.0	2.6	4.4	3.1	0.0
17	DN	Environmental Qualification Discovery Work and Scope Reduction	38458	Regulatory	Feb-09	Dec-10	75.7	42.3			0.0	0.0	18.4	30.7	6.0	0.0
18	ENG	Probabilistic Risk Assessment Upgrade	62440	Regulatory	Jan-09	Oct-10	26.8	12.0			0.0	0.0	5.1	9.4	3.9	0.0
19	PB	Unit 7 Calandria Tube Replacement	40669	Sustaining	Aug-08	Dec-08	17.8		19.8		0.0	17.1	0.6	0.0	0.0	0.0
20	PB	Fuel Channel Life Cycle Management Project	62444	Sustaining	Aug-09	Dec-13	24.9	12.3			0.0	0.0	2.5	9.7	7.7	4.0
21		**Subtotal**					**157.5**									

Notes:
1 Projects with expenditures during Test Period AND Completed/Deferred Projects (from EB-2007-0905 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).
3 Bold font indicates variance $\geq$ 10%, with explanation in Exhibit F2-T3-S3. Superceding Full Release is the new Total Project Cost.

Table 2
OM&A Project Listing - Nuclear
Facility Projects - Released Amount and Balance to be Released
Projects $5M - $10M Total Project Cost[1]

Line No.	Facility	Project Name	Category	Project Description	Start Date	Final In-Service Date	Total Project Cost ($M) (Note 2)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		ONGOING PROJECTS FROM EB-2007-0905					
1	DN	Steam Generator Water Lancing (Future campaigns)	Sustaining	Remove deposits from secondary side of Steam Generators to prevent under-deposit corrosion.	Apr-07	Apr-11	9.4
2	DN	Standby Generator Gas Generator and Power Turbine Overhaul	Sustaining	Complete overhaul and refurbishment of the Standby Generators	Dec-06	Dec-11	7.7
3	PB	Worker Safety Modifications for Feedwater Chemical Addition	Regulatory	Comply with OHSA limits for hydrazine exposure and provide overpressure protection.	Sep-01	Oct-11	5.3
4	PB	Digital Control Computer Obsolesence Management	Sustaining	Upgrade display hardware, replace necessary components, and procure critical spares.	Aug-03	Nov-11	5.9
5	DN	Fuel Handling Power Track Improvement	Sustaining	Modify Fuel Handling Power Track to improve reliability and add condition monitoring capability.	May-07	Nov-11	5.0
6		**Subtotal**					**33.3**
		COMPLETED PROJECTS FROM EB-2007-0905					
7	PB	Standby Generator Upgrade	Sustaining	Improve standby generator reliability through equipment upgrade and replacement.	Mar-00	Apr-08	8.9
8	PA	Vacuum Building Leakage Repairs	Sustaining	Perform repairs to the Vacuum Building to reduce air in-leakage.	Apr-06	Dec-08	6.0
9	PB	Remote Emergency Power Generator (Op Costs)	Regulatory	Operating costs of the temporary Remote Emergency Power Generator.	Jun-04	Dec-08	5.9
10	PB	Main Output Transformer Subsurface Investigation	Sustaining	Investigate, confirm and arrest the possibility of costly damage and/or forced outages caused by sub-surface instability under the Main Output Transformers.	Jun-05	Dec-08	3.2
11	PB	Liquid Zone Control Pumps/Mounting Frame Replacement	Sustaining	Replace & relocate Liquid Zone Control Pumps to improve reliability and address obsolescence of existing pumps.	Apr-04	Jun-09	8.8
12	PB	Contractor Lunch Room Facility	Sustaining	Provide change, shower and lunch room facilities within the protected area and demolish old life-expired facility.	Apr-06	Aug-09	5.9
13	PA	Administration Building Rehab	Sustaining	Upgrade Administration Building structures and systems to current codes and requirements.	Jul-07	Dec-09	1.6
14	DN	Steam Generator Water Lancing	Sustaining	Remove deposits from secondary side of Steam Generators to prevent under-deposit corrosion.	Jan-04	Nov-08	8.8
15	PA	Vacuum Building Fiber Reinforced Plastic Components Modifications	Sustaining	Perform laboratory testing to confirm lifespan of fiber reinforced plastic in vacuum conditions and replace components as required.	Sep-07	Mar-09	1.4
15		**Subtotal**					**50.4**
		PROJECTS NOT IN EB-2007-0905					
16	PA	Standby Generator Automatic Voltage Regulator Upgrade	Sustaining	Replace the automatic voltage regulators for the standby generators.	Dec-05	Dec-11	7.7
17	PA	Vacuum Building Basement Improvements	Sustaining	Modify Vacuum Building equipment to improve reliability and maintainability.	Jul-08	May-10	6.1
18		**Subtotal**					**13.8**

Notes:
1 Projects with expenditures during Test Period AND Completed/Deferred Projects (from EB-2007-0905 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Table 3
OM&A Project Listing - Nuclear
Projects <$5M Total Project Cost[1]

Line No.	Sponsoring Division	Number of Projects	Total Project Cost ($M)	Average Cost Of All Projects ($M)
		(a)	(b)	(c)
	Facility Projects			
1	**Darlington NGS**	13	26.5	2.0
2	**Pickering A NGS**	12	21.3	1.8
3	**Pickering B NGS**	15	22.4	1.5
4	**Nuclear Support Divisions[2]**	12	15.6	1.3
5	**Total**	52	85.7	1.6

Notes:
1 Projects with expenditures during Test Period.
2 Nuclear Support Divisions includes Engineering, Projects & Mods, Supply Chain, Programs & Training, Inspection Mtce and Commercial Services, Facilities and PINO.

Table 4a
OM&A Project Listing - Nuclear
Facility Projects - Listed Work to be Released[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released)		
	Darlington NGS		
1	Retrofit Lighting in Main Control Room	Sustaining	2011 or Later
2	Hydrogen Cooling Temperature Control Valve 20 redesign	Sustaining	2011 or Later
3	Emergency Power Generator 1 Gas Generator & Power Turbine Overhall	Sustaining	2011 or Later
4	Upgrade Containment Boundary Isolation Valves	Sustaining	2011 or Later
5	Shutdown System 2 Radiation Reduction Tooling	Sustaining	2011 or Later
	Darlington NGS - Projects With Potential Cost > $10M		
6	Fuel Channel Closure Plug Leakage Elimination	Value Enhancing	2011 or Later
7	CSA N293.0-97 Fire Protection Plan	Regulatory	2011 or Later
	Pickering A NGS		
8	Emergency Coolant Injection Strainer Capacity Margin	Regulatory	2010
9	Pickering Incoming/Outgoing Tritiated D2O Transfer System - Tritium D2O Filling Station Filter Installation	Sustaining	2011 or Later
10	D2O Storage Tank Pressure Control Improvements	Sustaining	2011 or Later
11	Upgrader Plant Pickering Chiller Replacement	Sustaining	2011 or Later
12	Vault Vapour Recovery Dryer Capacity Improvement	Sustaining	2011 or Later
13	As Low As Reasonably Achievable (ALARA) Source Term/Dose Reduction	Sustaining	2011 or Later
14	Emergency Core Cooling Room Heating Ventilation Air Conditioning Upgrade	Sustaining	2011 or Later
15	Standby Generator High Pressure Emergency Coolant Injection Load Test	Sustaining	2011 or Later
	Pickering A NGS - Projects With Potential Cost > $10M		
16	Unit 1 & 4 Fuel Channel East Pressure Tube Shift	Sustaining	2011 or Later
	Table continues on Ex. F2, Tab 3, Sch. 3 Table 4b		

Notes:
1 Projects with potential expenditures during Test Period.

Table 4b
OM&A Project Listing - Nuclear
Facility Projects - Listed Work to be Released[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Facility Projects (Listed Work to be Released) - Continued		
	Pickering B NGS		
17	Reactor Building Service Water Dechlorination and Municipal/Industrial Strategy for Abatement Cleanup	Sustaining	2010
18	Machine Guarding Improvement on Low Risk Equipment	Regulatory	2009
19	Main Output Transformer 8 Foundation Settlement	Sustaining	2010
20	Boiler Blowdown Pipe Support	Sustaining	2010
21	Update Priority 2 System Design Requirements	Sustaining	2011 or Later
22	Ignitable Fluid Dyking and Containment Installation	Sustaining	2011 or Later
	Pickering B NGS - Projects With Potential Cost > $10M		
23	U8 Moderator Annubar Retrieval	Sustaining	2010
	Nuclear Engineering		
24	Hydrogen Effusion Monitor Development	Sustaining	2011 or Later
	Nuclear Programs & Training		
25	Fuelling Machine Stellite Ball Replacement - Phase 2	Sustaining	2011 or Later
	Nuclear Programs & Training - Projects With Potential Cost > $10M		
26	10 km Alert Sirens	Regulatory	2011 or Later
	Inspection & Maintenance Services		
27	Pickering Irradiated Fuel Bay Fuel Inspection Camera Improvement	Sustaining	2011 or Later
	Facilities & Facilities Management		
28	Life Expired Buildings Demolition	Sustaining	2011 or Later

Notes:
1 Projects with potential expenditures during Test Period.

OUTAGE OM&A – NUCLEAR

1.0 PURPOSE

This evidence presents the methodology for the derivation of the nuclear outage OM&A budget. It also presents the actual and forecast outage OM&A costs for the period 2007 - 2012.

2.0 OVERVIEW

The nuclear outage OM&A expense for 2007 - 2012 is provided in Ex. F2-T4-S1 Table 1. The test period outage OM&A expense of $214.8M in 2011 and $201.1M in 2012 forms part of the OM&A expense in the nuclear revenue requirement.

Nuclear planned outages are necessary to execute inspection and maintenance work on systems and equipment where access is not possible under normal operating conditions. Outage work activities generally fall into two categories: a) inspection and maintenance work related to effective asset management and regulatory requirements; and, b) project work. Planned outages also give OPG an opportunity to perform systems and equipment upgrades, configuration changes, and other improvements and modifications.

Completion of specific outages requires both base work program resources and incremental resources. Base work program resource costs, including the cost of regular labour, are captured within nuclear base OM&A (see Ex. F2-T2-S1). Incremental resource costs over and above the base work program resources are captured in outage OM&A. Outage OM&A costs include incremental short-term labour to meet expected non-regular staffing needs for peak work periods, materials, and the costs for specialized services such as inspection and maintenance work (e.g., feeder piping, fuel channel, and steam generator inspections) provided by Inspection, Maintenance and Commercial Services (“IM&CS”). Accordingly, the total costs of an outage are divided between nuclear base OM&A and outage OM&A.

The costs associated with the completion of projects undertaken during an outage are captured in either project OM&A or capital, as applicable.

The key consideration in assessing the need for incremental short term labour resources during an outage is the ability to optimize available base work resources and skills. For example, the availability of regular maintenance staff for outage work has to be assessed relative to: a) the demand for regular staff to meet the ongoing maintenance requirements of the running units; and, b) the peak staff resources required to complete the outage scope within the outage schedule. The forecast of outage OM&A is focused on the need for, and cost of, the incremental labour resources (e.g., temporary staff and external contractors) required over and above regular base staff to execute the outage as per the outage schedule.

OPG uses incremental staffing for peak labour needs because it is more cost effective to bring on incremental resources as needed than to maintain permanent outage staff. It also allows OPG to obtain the specialized skills that are needed (given the highly specialized nature of outage inspection and maintenance, specialized skills are required from IM&CS or external contractors). In addition, in some cases, the nature of the maintenance activity mandates the use of external, original equipment manufacturer expertise. OPG's use of incremental staffing resources to complete outage work activities provides it with important resource flexibility and is consistent with industry practice.

3.0 DEVELOPING THE OUTAGE OM&A BUDGET

The nuclear outage OM&A budget is established through the business planning process (see Ex. F2-T1-S1). Each station prepares its own five year outage OM&A budget. The nuclear support groups also prepare five year outage OM&A budgets to reflect the cost of their required contribution to the planned outages.

The nuclear outage OM&A budget is derived in conjunction with the development of the approved generation plans and outage schedule for each station as part of the five year Integrated Plan, which is discussed in detail at Ex. E2-T1-S1.

The first two years of the Integrated Plan are subject to the most detailed reviews. In particular, identification of the major work scope to be completed in a planned outage is finalized, the do-ability within the scheduled timeframe is reviewed, resources are assessed and economic justification of discretionary activities is analyzed within the constraints of the business plan. This establishes the approved scope, duration, and outage cost. The last three years of the Integrated Plan are subject to lesser scrutiny, given that during the five year cycle, the outage scope, duration, and costs of these later years will be subject to additional assessments (e.g., due to emergent issues or changes in life cycle management processes, or regulatory requirement changes that impact scope) as they come closer to the year of execution.

3.1 Resource Types

As shown in Ex. F2-T4-S1 Tables 2 - 10, outage OM&A for each station and related nuclear support services are budgeted on the basis of the resource types described below:

- Non-Regular Labour: The cost for temporary labour. These staff are on OPG's payroll and are directly supervised by OPG employees. They are usually comprised of construction labourers and trade workers (e.g., electricians) and co-op students.
- Overtime: The cost of overtime incurred by regular labour, non-regular labour, and augmented staff during the outage. While overtime costs for regular staff working on an outage is budgeted to outage OM&A, regular labour costs, with the exception of IM&CS regular labour, is budgeted as base OM&A.
- Augmented Staff: The cost of non-regular staff for peak work periods. These temporary additions to staff complements are directly supervised by OPG staff but are not on OPG's payroll. They are usually professional staff such as engineers, assessors, operation procedure writers or analysts.
- Materials: The cost of materials and supplies used for the outage.
- Other Purchased Services: The cost of outside contractors and their employees. These contractors and employees are not on OPG's payroll and the employees are under the supervision of the contractor. In addition, other purchased services include charges by OPG's IM&CS division. Further discussion of IM&CS services can be found at Ex. G2-T1-S1. Other purchased services may also include the costs of major equipment refurbishments.

3.2 Costing of Required Resource Types

For the resource types referenced above, the forecast of outage OM&A costs are developed by each station through the iterative process described below:

- The work load is analyzed with respect to the work orders, sequencing and the skills and resources required.
- Work orders are examined for the type and number of tasks involved to complete the work orders.
- Tasks are grouped into blocks of activities, either by complementary groupings or by those attached to specific equipment. These blocks are placed in "windows" for execution purposes.
- Using productivity information from past outages (such as total hours per day, total hours per work order/task, and number of tasks/work orders), a time budget is established. By considering the type of skilled resources required to execute the work, a cost estimate can be developed for regular labour, which is included in base OM&A. The outage duration and schedule along with historical statistical information (overtime hours per work order/task) allows OPG to identify the incremental labour required. For example, the outage's duration and schedule establish "do-ability constraints" (e.g., congested work areas and operational constraints) thereby delineating needs for incremental peak labour and overtime.
- Work planning yields information on the specific parts and/or materials needed for the outage. Information referenced from past outage and risk assessments is used to estimate the supplies required and the contingency materials needed. Contingency materials are those parts or materials that are ordered, due to the lead times required, in anticipation of a need for the part or material potentially arising during the outage even though it was not specifically identified as being part of the outage scope.
- Work planning also provides information regarding preparation requirements, pre-requisites, and associated execution requirements. The cost of this additional support work is estimated in a manner similar to direct work.
- For contractor services, OPG's outage OM&A budgets are based on historical unit hourly rates charged by the contractors (adjusted for inflation) or on actual tender quotes

(depending upon the timeframe of the planned outage), multiplied by the level of planned work activity.

- IM&CS direct costs for each OPG outage are derived based on the work, time and resources required. These IM&CS direct costs are then allocated to each station for inclusion in each station's business plans.

OPG continues to be engaged in multi-year outage improvement initiatives focused on improving outage performance and costs. As discussed in more detail at Ex. F2-T1-S1 and Ex. E2-T1-S1, OPG is pursuing an Outage Improvement Strategy initiative developed during the Phase 2 Benchmarking. It has been incorporated into the 2010 - 2014 Business Plan and is expected to impact outage costs.

The Outage Improvement Strategy is designed to allow OPG to pursue opportunities to reduce outage costs, as well as improve reliability and generation performance across the company's nuclear fleet. For example, by improving fleet contractor management procedures, OPG is targeting improved contractor productivity/efficiency by increasing the amount of work done each day by external contractors. The objective of this fleet-wide initiative is to reduce the duration and the cost of outages at OPG. Improved scheduling of outages will result in a more effective utilization of resources resulting in less demand for external purchased services and overtime. Improved scope determination will result in an ability to reduce material requirements in inventory as well as better plan for securing purchased services.

Beginning in 2010, a new fleet-wide approach has been implemented for improving the forecast of outage costs through the introduction of Functional Outage Groupings. The implementation of Functional Outage Groupings will facilitate OPG's ability to analyze fleet-wide outage costs by station and by outage. This will assist OPG in identifying and implementing fleet-wide best practices.

4.0 OUTAGE OM&A VARIANCES

Each of the components that drive the outage OM&A budget (duration, scope, and resources) can vary from the forecast. OPG updates its forecast of future planned outages, work activity, and related costs through the Integrated Plan review process. Consequently, scope definition is more precise for near-term outages compared to the later years of the five year outage planning cycle.

Some of the variables that can give rise to changes in the five year outage OM&A plan include:

- The results from ongoing OPG outage inspection and maintenance work, which could impact the scope of work planned for future outages, even if the future outages are at a different unit or station.
- New CNSC regulatory requirements may add to outage scope and costs.
- Operational information shared within the nuclear industry that provides OPG with information about potential emerging issues from other nuclear industry operators. Information about these emergent issues can result in additional scope and costs in future OPG outages (i.e., inspections would assess the extent to which the emergent issue impacts, if at all, OPG’s nuclear units thereby potentially resulting in additional scope and costs in future outages).
- The impact of collective bargaining agreements, internal and external, on labour costs.
- The impact of inflation or vendor issues on material costs.
- A decision by OPG to curtail the scope of an outage resulting in additional work/additional scope being added to a future outage, or conversely, a decision to advance scope from a future outage into a current outage.
- In some cases the scope of work can be increased without impacting outage duration (but increasing outage OM&A costs) if the work can be performed in parallel with other critical path activities.

5.0 OUTAGE CATEGORIES

5.1 Forecast Outage OM&A

The outage OM&A forecast is derived from the incremental costs associated with planned outages in the Integrated Plan (see Ex. E2-T1-S1). As noted previously, the outage OM&A forecast focuses on the need for and cost of the incremental labour resources (e.g., temporary staff and external contractors, overtime) required over and above regular base staff to execute planned outages, along with the various materials and suppliers required.

OPG does not forecast incremental outage costs for forced outages or forced derates, as OPG typically does not use incremental non-regular labour or augmented staff for these events. This is because OPG will re-prioritize base work during a forced outage or forced derate to allow regular base OM&A work resources to focus on fixing the cause of the forced outage so that OPG can return the unit to operation as quickly as possible. A consequence of diverting base resources from routine maintenance work during forced outages is to delay OPG's efforts towards reducing elective and corrective maintenance backlogs and implementing improvement strategies.

5.2 Actual Outage OM&A

Actual outage OM&A will include the actual incremental costs of the planned outages. In addition, the actual outage OM&A will include unbudgeted costs due to forced extensions of planned outages, planned outage extensions, or unbudgeted planned outages. Generally, the incremental unit cost of an outage extension tends to be lower compared to the unit cost of a planned outage.

All actual costs incurred due to forced outages, planned derates or forced derates, that could include overtime costs for regular base staff, are recorded in the base OM&A.

6.0 OUTAGE OM&A 2007 - 2012

The main drivers to outage OM&A variances (year-over-year and actual to budget) are the number of outages, scope, planned duration, and actual duration (i.e., extensions of planned outages in a year). The most significant drivers of outage OM&A costs over the period 2007 - 2012 are:

- A four unit vacuum building outage at Darlington in 2009.
- A six unit vacuum building outage at Pickering in 2010.
- Two outages at Darlington in 2010 compared to one in each of 2011 and 2012 consistent with the 36-month outage cycle.
- Additional planned outage days at Pickering B during 2010 - 2012 as a result of the Continued Operations initiative. The need for the Pickering B Continued Operations initiative is discussed in greater detail at Ex. F2-T2-S3.

More detailed explanations of the various factors that have, or are expected to contribute to the year-over-year outage OM&A variances during the period 2007 - 2012 are provided in Ex. F2-T4-S2.

Table 1
Outage OM&A - Nuclear ($M)

Line No.	Division	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
1	Darlington NGS	97.1	83.2	109.8	106.7	64.2	59.0
2	Pickering A NGS	42.1	25.0	64.1	68.6	52.0	52.4
3	Pickering B NGS	69.6	82.9	70.2	90.5	81.1	74.9
4	Pickering B Continued Operations	0.0	0.0	2.8	1.9	13.0	10.6
5	**Total Stations**	208.8	191.1	246.8	267.8	210.2	196.9
	Nuclear Support Divisions						
6	Engineering	1.6	1.2	1.1	1.1	1.1	1.1
7	Projects & Modifications	2.6	1.8	2.9	3.1	1.5	1.1
8	Facilities Management	0.0	0.1	0.2	0.3	0.1	0.1
9	Programs & Training	1.0	0.6	1.0	0.8	0.5	0.5
10	Supply Chain	1.6	1.3	2.8	1.6	1.4	1.4
11	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0
12	Inspection & Mtce Services[1]	0.0	0.0	0.0	0.0	0.0	0.0
13	Commercial Services	0.0	0.0	0.0	0.0	0.0	0.0
14	Nuclear Level Common	0.0	0.0	0.0	10.0	0.0	0.0
15	**Total Support**	6.8	5.0	8.0	16.8	4.6	4.2
16	**Total**	215.6	196.1	254.8	284.6	214.8	201.1

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Numbers may not add due to rounding.

Table 2
Outage OM&A by Resource Type - Nuclear ($M)
Plan - Calendar Year Ending December 31, 2012

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.6	11.2		11.5	31.5	0.3	59.0
2	Pickering A NGS					5.9	46.5		52.4
3	Pickering B NGS		2.8	12.0	3.7	12.5	43.9		74.9
4	Pickering B Continued Operations					5.1	5.5		10.6
5	**Total Stations**	0.0	7.3	23.2	3.7	34.9	127.5	0.3	196.9
	Nuclear Support Divisions								
6	Engineering						1.1		1.1
7	Projects & Modifications		0.2	1.0			(0.1)		1.1
8	Facilities Management			0.1					0.1
9	Programs & Training			0.5					0.5
10	Supply Chain			1.4					1.4
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.2	3.1	0.0	0.0	1.0	0.0	4.2
16	**Total**	0.0	7.5	26.3	3.7	34.9	128.5	0.3	201.1

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Numbers may not add due to rounding.

Table 3
Outage OM&A by Resource Type - Nuclear ($M)
Plan - Calendar Year Ending December 31, 2011

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		5.4	11.9		11.5	35.1	0.2	64.2
2	Pickering A NGS					6.4	45.6		52.0
3	Pickering B NGS		6.2	12.7	2.9	12.5	46.9		81.1
4	Pickering B Continued Operations					4.4	8.5		13.0
5	**Total Stations**	0.0	11.6	24.6	2.9	34.8	136.1	0.2	210.2
	Nuclear Support Divisions								
6	Engineering						1.1		1.1
7	Projects & Modifications		0.2	1.3			(0.0)		1.5
8	Facilities Management			0.1					0.1
9	Programs & Training			0.5					0.5
10	Supply Chain			1.4					1.4
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.2	3.3	0.0	0.0	1.1	0.0	4.6
16	**Total**	0.0	11.8	27.9	2.9	34.8	137.2	0.2	214.8

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 4
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2010

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		10.6	20.9		16.6	58.4	0.2	106.7
2	Pickering A NGS		5.4	11.0	0.4	14.8	37.1	0.0	68.6
3	Pickering B NGS		6.6	17.5	2.7	15.3	48.5	0.0	90.5
4	Pickering B Continued Operations					1.4	0.5		1.9
5	**Total Stations**	0.0	22.5	49.4	3.1	48.1	144.5	0.3	267.8
	Nuclear Support Divisions								
6	Engineering						1.1		1.1
7	Projects & Modifications		0.4	1.8			0.9		3.1
8	Facilities Management			0.1		0.0	0.2		0.3
9	Programs & Training		0.0	0.5	0.0		0.2		0.8
10	Supply Chain			1.6					1.6
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common						10.0		10.0
15	**Total Support**	0.0	0.4	4.0	0.0	0.0	12.4	0.0	16.8
16	**Total**	0.0	22.9	53.4	3.1	48.1	156.8	0.3	284.6

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 5
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2009

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		6.6	20.8	0.3	14.2	66.7	1.2	109.8
2	Pickering A NGS		3.1	10.1	16.8	4.5	29.6	0.0	64.1
3	Pickering B NGS		4.9	16.5	1.1	12.0	35.6	0.1	70.2
4	Pickering B Continued Operations					2.5	0.3	0.0	2.8
5	**Total Stations**	0.0	14.6	47.3	18.2	33.1	132.3	1.4	246.8
	Nuclear Support Divisions								
6	Engineering			0.1			1.0		1.1
7	Projects & Modifications		0.9	2.0	0.0				2.9
8	Facilities Management		0.1	0.1		0.0			0.2
9	Programs & Training		0.1	0.7			0.2		1.0
10	Supply Chain		0.5	2.2	0.0				2.8
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	1.7	5.1	0.0	0.0	1.2	0.0	8.0
16	**Total**	0.0	16.2	52.4	18.2	33.1	133.4	1.4	254.8

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 6
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2009

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.0	16.5	3.6	10.7	32.6	4.5	71.8
2	Pickering A NGS		2.5	6.6		5.3	46.7		61.1
3	Pickering B NGS		2.4	11.0	3.6	10.0	43.5		70.5
4	Pickering B Continued Operations								0.0
5	**Total Stations**	0.0	9.0	34.1	7.2	25.9	122.8	4.5	203.4
	Nuclear Support Divisions								
6	Engineering						1.1		1.1
7	Projects & Modifications						1.6		1.6
8	Facilities Management			0.1					0.1
9	Programs & Training			0.4					0.4
10	Supply Chain			1.4					1.4
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.0	1.9	0.0	0.0	2.6	0.0	4.5
16	**Total**	0.0	9.0	35.9	7.2	25.9	125.5	4.5	207.9

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Numbers may not add due to rounding.

Table 7
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2008

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.2	13.8	0.5	22.2	42.4	0.1	83.2
2	Pickering A NGS		1.2	3.1	5.1	6.8	8.7	0.0	25.0
3	Pickering B NGS		6.7	19.5	0.5	15.1	41.0	0.1	82.9
4	Pickering B Continued Operations								0.0
5	**Total Stations**	0.0	12.1	36.4	6.2	44.1	92.1	0.2	191.1
	Nuclear Support Divisions								
6	Engineering			0.0	0.0		1.2		1.2
7	Projects & Modifications		0.3	1.4		0.1	(0.0)		1.8
8	Facilities Management		0.0	0.0					0.1
9	Programs & Training		0.0	0.5		0.0		0.0	0.6
10	Supply Chain		0.1	1.2					1.3
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.5	3.1	0.0	0.1	1.2	0.0	5.0
16	**Total**	0.0	12.6	39.6	6.2	44.1	93.3	0.3	196.1

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 8
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2008

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		4.0	11.7	0.6	19.8	35.6	0.7	72.4
2	Pickering A NGS		2.4	6.3		5.0	34.7		48.5
3	Pickering B NGS		4.4	12.9		11.0	38.4		66.7
4	Pickering B Continued Operations								0.0
5	**Total Stations**	0.0	10.8	30.9	0.6	35.8	108.7	0.7	187.5
	Nuclear Support Divisions								
6	Engineering						1.0		1.0
7	Projects & Modifications						1.6		1.6
8	Facilities Management			0.1					0.1
9	Programs & Training			0.6				0.0	0.6
10	Supply Chain			1.3					1.3
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.0	1.9	0.0	0.0	2.6	0.0	4.6
16	**Total**	0.0	10.8	32.8	0.6	35.8	111.4	0.7	192.2

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 9
Outage OM&A by Resource Type - Nuclear ($M)
Actual - Calendar Year Ending December 31, 2007

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		6.9	20.9	1.0	15.7	52.5	0.1	97.1
2	Pickering A NGS		3.0	7.0	1.1	5.3	25.7	0.0	42.1
3	Pickering B NGS		4.2	15.9	5.5	13.7	30.3	0.1	69.6
4	Pickering B Continued Operations								0.0
5	**Total Stations**	0.0	14.1	43.7	7.6	34.7	108.5	0.2	208.8
	Nuclear Support Divisions								
6	Engineering			0.0	0.0		1.6		1.6
7	Projects & Modifications		0.6	1.2		0.0	0.8	0.0	2.6
8	Facilities Management		0.0	0.1			(0.0)		0.0
9	Programs & Training		0.4	0.4	0.1	0.0		0.0	1.0
10	Supply Chain		0.0	1.6	0.0	0.0			1.6
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	1.0	3.3	0.1	0.0	2.4	0.0	6.8
16	**Total**	0.0	15.1	47.1	7.7	34.7	110.9	0.2	215.6

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Numbers may not add due to rounding.

Table 10
Outage OM&A by Resource Type - Nuclear ($M)
Budget - Calendar Year Ending December 31, 2007

Line No.	Division	Regular Labour	Non-Regular Labour	Overtime	Augmented Staff	Materials	Other Purchased Services	Other	Total Outage OM&A
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Nuclear Stations								
1	Darlington NGS		7.4	20.2	4.2	11.5	42.1	0.4	85.7
2	Pickering A NGS			5.9		6.4	28.8		41.0
3	Pickering B NGS		5.7	11.6		10.0	36.6		63.9
4	Pickering B Continued Operations								0.0
5	**Total Stations**	0.0	13.1	37.7	4.2	27.9	107.4	0.4	190.6
	Nuclear Support Divisions								
6	Engineering						1.0		1.0
7	Projects & Modifications								0.0
8	Facilities Management			0.1					0.1
9	Programs & Training			0.4					0.4
10	Supply Chain			1.5					1.5
11	Performance Imprvmnt & Oversight								0.0
12	Inspection & Mtce Services[1]								0.0
13	Commercial Services								0.0
14	Nuclear Level Common								0.0
15	**Total Support**	0.0	0.0	1.9	0.0	0.0	1.0	0.0	2.9
16	**Total**	0.0	13.1	39.6	4.2	27.9	108.5	0.4	193.5

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

COMPARISON OF NUCLEAR OUTAGE OM&A

1.0 PURPOSE

This evidence presents period-over-period comparisons of outage OM&A broken down by station.

2.0 OVERVIEW

This evidence supports the approvals sought for nuclear outage OM&A. Exhibit F2-T2-S2 Tables 1a, b and c set out the comparisons of nuclear outage OM&A for the historical, bridge and test years. Exhibit F2-T4-S2 Tables 2 - 10 set out outage OM&A costs by resource type for calendar years 2007 - 2012. Definitions of the resource types are found in Ex. F2-T4-S1.

The scope of outage work over the 2007 - 2012 period is different in each year, reflecting various inspection and maintenance activities (fuel channels, steam generators, and turbine/generators). The largest component of outage OM&A is typically Other Purchased Services, which represents contracted services from external contractors and work performed by OPG's Inspection and Maintenance Commercial Services group ("IM&CS"). As discussed in Ex. F2-T4-S1, the cost of IM&CS outage work for OPG generating stations is captured as a component of each station's outage OM&A costs.

There are a number of reasons why comparing the year-to-year variation in outage OM&A amounts budgeted or spent is not meaningful. First, while there are many standard elements of outage scope (see Ex. E2-T1-S1), there can also be unique activities, programs or major equipment campaigns that are unit-specific, such as single fuel channel replacement. Second, the scope of an individual outage is primarily a function of the unit's condition at a point in time. Units do not necessarily age or deteriorate in a uniform way or at a uniform rate. For instance, it is highly unlikely that the outage scope for a particular unit in a certain year of operation will precisely match the outage scope for a different unit in the same year of its operation. Third, a major driver to the variability in Pickering B outage OM&A costs over the period 2010 - 2012 will be activities in support of Continued Operations.

For these reasons, the following explanations of the year-over-year variances in outage OM&A costs are limited to a description of the differences in scope and duration of the outages in each year.

3.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

<u>2012 Plan versus 2011 Plan</u>

Outage OM&A expenditures are forecast to decrease by $13.7M (6.4 per cent) in 2012 plan compared to 2011 plan. The main drivers to this decrease in outage OM&A costs are as follows:

- Pickering A: Outage costs are expected to be flat year-over-year for 2012 as compared to 2011. Pickering A is forecasting additional outage costs for feeder replacements in 2012 compared to 2011 ($8.0M) but this is offset by lower costs due to reduced life cycle management work in 2012 (i.e., reduced inspection programs such as wet scrapes and boiler inspections)
- Pickering B: Outage OM&A costs are forecast to decrease by $8.6M (9.1 per cent) in 2012 compared to 2011. This reduction is primarily a function of the fact that the single fuel channel replacement undertaken in 2011 will not be repeated in 2012. As well, there is less outage scope in 2012 as a result of less spacer location and relocation ("SLAR") related to the Continued Operations initiative in 2012 compared to 2011.
- Darlington: Outage OM&A costs are forecast to decrease by $5.1M (7.9 per cent) in 2012 as compared to 2011. This decrease is primarily due to savings from undertaking fewer feeder replacements in 2012 compared to 2011.

<u>2011 Plan versus 2010 Budget</u>

Outage OM&A expenditures are forecast to decrease by $69.9M (24.5 per cent) in 2011 plan compared to 2010 budget. The main drivers to this decrease in outage OM&A costs are as follows:

- Pickering A: Outage costs are expected to be lower by $16.7M (24.3 per cent) in 2011 as compared to 2010 primarily because costs incurred in 2010 related to the Pickering vacuum building outage ("VBO") will not be repeated in 2011. Pickering A will also have reduced outage costs in 2011 as it does not intend to undertake a turbine replacement program (savings of $6.5M).

- Pickering B: Outage OM&A costs are forecast to be higher by $1.6M (1.7 per cent) in 2011 compared to 2010 primarily due to an increase in expenditures for Continued Operations (e.g., additional SLAR). Also, Pickering B's outage costs in 2011 include additional costs ($10M) for a single fuel channel replacement. However, Pickering B's outage costs in 2011 are favourably impacted compared to 2010 because of costs incurred in 2010 relative to the Pickering VBO.
- Darlington: Outage OM&A costs are forecast to decrease by $42.6M (39.9 per cent) in 2011 compared to 2010 primarily as a result of the 36-month outage cycle, as there will be only one planned outage in 2011 compared to two planned outages in 2010. In addition, 2011 outage costs are lower as 2010 includes turbine blade replacement costs.

The 2010 budget also includes a forecast Nuclear Level Common outage OM&A expenditure of $10.0M. There is no Nuclear Level Common cost forecast in 2011. The $10M Nuclear Level Common outage OM&A expenditure in 2010 represents an amount held by the Chief Nuclear Officer in reserve related to the Pickering 2010 VBO.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2010 Budget versus 2009 Actual

Outage OM&A expenditures are expected to increase by $29.8M (11.7 per cent) in the 2010 budget compared to 2009 actual. The main drivers to this increase in outage OM&A costs are as follows:

- Pickering A: Outage costs are expected to be higher by $4.6M (7.1 per cent) in 2010 compared to 2009 primarily due to the 2010 Pickering VBO ($19.3M) offset by higher costs in 2009 due to scope increases for the Unit 4 outage.
- Pickering B: Outage OM&A costs are forecast to be higher by $19.5M (26.7 per cent) in 2010 compared to 2009 primarily because additional costs (e.g., inspection and maintence services) will be incurred in 2010 related to scope increase for the Pickering VBO along with 2 feeder replacements.

- Darlington: Outage OM&A costs are forecast to be lower by $3.1M (2.8 per cent) in 2010 compared to 2009, primarily because costs incurred in 2009 related to the four unit VBO will be avoided in 2010 and there are avoided IM&CS inspection costs for the calandria, single fuel channel replacement ("SFCR") and feeders. A partial offset to these lower costs is that Darlington will have two planned outages in 2010 compared to only one planned outage in 2009 as a result of the 36-month outage cycle.

The 2010 budget also includes a forecast Nuclear Level Common outage OM&A expenditure of $10.0M for the 2010 Pickering VBO. There was no equivalent Nuclear Level Common expenditure in 2009.

5.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

<u>2009 Actual versus 2009 Budget</u>

Actual outage OM&A costs in 2009 are $46.9M (22.6 per cent) over budget. The main drivers to the variance between actual and budget 2009 outage OM&A costs are as follows:

- Pickering A: Actual outage OM&A costs are higher by $3M (4.7 per cent) compared to budget. In 2009, higher outage costs were incurred due to scope increases related to the Unit 4 outage, as well as additional work in 2009 due to the deferral of fall 2008 outage, partially offset by the deferral of the replacement of four feeders ($4.0M) which had been included in the 2009 budget.
- Pickering B: Actual outage OM&A costs are higher by $2.4M (3.4 per cent) compared to budget primarily due to unbudgeted outage OM&A expenditures for Pickering B Continued Operations.
- Darlington: Actual outage OM&A costs are higher by $38.0M (52.9 per cent) compared to budget primarily due to increased expenditures for overtime and purchased services during the VBO. The 2009 VBO budget that was filed in EB-2007-0905 was prepared one and one-half years in advance of the VBO and did not contemplate the additional scope additions that were made as part of the final VBO work plan. The VBO was also subject to unanticipated equipment degradation that resulted in critical path delays and Unit 3 planned outage schedule delays on inspection programs. Darlington also experienced additional costs for unbudgeted work related to single fuel channel replacement;

increased inspection and maintenance costs (boilers/turbine), and increased costs for feeder replacements.

2009 Actual versus 2008 Actual

Actual outage OM&A costs in 2009 were $254.8M, which is an increase of $58.7M (29.9 per cent) over actual outage OM&A costs in 2008 of $196.1M. With respect to year-over-year comparisons between 2009 and 2008, the key drivers were:

- Pickering A: Actual outage OM&A costs in 2009 were higher by $39.1M (156.4 per cent) compared to 2008 due to the deferral of the fall 2008 outage into 2009, higher costs due to scope increases for the Unit 4 outage, and costs incurred in 2009 related to preparation for the 2010 VBO ($2.0M).
- Pickering B: Actual outage OM&A costs in 2009 were lower by $9.9M (12 per cent) compared to 2008 due to no feeder replacements in 2009 offset by increased inspection and maintenance costs and a spindle refurbishment, and $2.8M expenditure for Pickering B Continued Operations in 2009. There were no outage OM&A expenditures on Continued Operations in 2008.
- Darlington: Actual outage OM&A costs in 2009 were higher by $26.5M (31.9 per cent) compared to actual outage OM&A costs in 2008 due to increased expenditures in 2009 for the Darlington VBO, additional costs for an unbudgeted SFCR; increased inspection and maintenance costs and unbudgeted increase in costs due to increase duration and scope of outages in 2009, partially offset by the fact that there was no turbine replacement in 2009.

2008 Actual versus 2008 Budget

Actual outage OM&A costs in 2008 were $3.9 M (2.1 per cent) over budget for OPG's nuclear fleet. The main drivers to the variance between actual and budget 2008 outage OM&A costs are as follows:

- Pickering A: Budget costs were lower by $23.5M due to the deferral of the fall 2008 planned outage until 2009 ($30.9M), partially offset by the decision to refurbish the spindles in 2008 in advance of the outage.
- Pickering B: Actual outage OM&A expenditures ($82.9M) were $16.2 M more than budget. This is attributable to higher overtime and temporary labour costs related to the advancement of the Unit 7 planned outage as well as higher than budgeted planning and assessing costs to support the Unit 5 2009 planned outage, partially offset by under expenditures on the 2010 VBO outage preparation work.
- Darlington: Actual outage OM&A expenditures ($83.2M) were $10.9M more than budget. This is primarily due to higher costs for planning and assessing work to support the 2009 VBO and higher feeder inspection costs for the 2008 Unit 1 planned outage, partially offset by lower than budgeted outage costs for turbine blade replacement and feeder replacement.

<u>2008 Actual versus 2007 Actual</u>

Actual outage OM&A costs in 2008 were $196.1M, which is a decrease of $19.5M (9 per cent) over actual outage OM&A costs in 2007 of $215.6M. With respect to comparisons between 2008 and 2007, the key drivers were:

- Pickering A: Outage costs were lower by $17.1M (40.6 per cent) in 2008 compared to 2007 primarily due to the deferral of the fall 2008 planned outage until 2009 ($30.9M) partially offset by the decision to refurbish the spindles in 2008 in advance of the outage ($6.3M).
- Pickering B: Outage OM&A costs were higher by $13.3M (19.1 per cent) in 2008 than 2007. In 2008, Unit 7 was subject to a major unforeseen forced outage that required the replacement of a calandria tube in Unit 7. To mitigate the impact of the forced outage, OPG brought forward and completed outage work from the planned Unit 7 fall outage into the forced outage. The higher outage OM&A costs in 2008 compared to 2007 primarily reflect the higher overtime and temporary labour costs related to the advancement of the Unit 7 planned outage.
- Darlington: 2008 outage OM&A costs were lower by $13.9M (14.3 per cent) compared to 2007 reflecting that, as part of the transition to the three-year outage cycle, two units

were on outage in 2007 for a total of 134 days versus only one unit on planned outage in 2008 for a total of 75 days. In addition there was an unbudgeted planned outage in 2007. The 2008 outage OMA costs compared to 2007 were impacted by planning and assessing work undertaken in 2008 to support the 2009 VBO.

2007 Actual versus 2007 Budget

Actual outage OM&A costs in 2007 were $22.1M (11 per cent) over budget for OPG's combined nuclear fleet, principally due to higher than planned outage OM&A costs at Darlington ($11.4M or 13 per cent). Actual outage OM&A costs were $5.7M (9 per cent) over budget at Pickering B and $1M (2.4 per cent) over budget at Pickering A.

The key drivers behind these budget variances were:

- Pickering A: Outage OM&A was 2.4 per cent over budget reflecting incremental costs for overtime, decontamination services and adjuster rod repairs as well as higher IM&CS costs related to boiler inspections and mobilization costs related to advancing fall planned outage work into the summer inter-station transfer bus ("ISTB") outage.
- Pickering B: Outage OM&A costs were 9 per cent over budget. Better than budget performance on the Unit 6 fall outage which resulted in outage OM&A cost savings of approximately $5.5M was offset by unforeseen costs arising from turbine spindle repairs, advanced work associated with the Unit 8 spring 2008 outage and costs incurred due to the inadvertent release by a third party contractor of resin into the demineralized water system.
- Darlington: Outage OM&A costs were 13 per cent over budget. A major component of this overage was related to the decision, after the business plan was approved, to utilize regular labour resources for the ongoing maintenance requirements of the running units. This required obtaining additional external contractor services to complete the planned outage work. This approach is consistent with the outage staffing strategy and the need to optimize available base work resources and skills as set out in Ex. F2-T4-S1, section 2. In addition, the Unit 4 outage incurred additional overtime and material costs due to a large amount of discovery work.

Table 1a
Comparison of Outage OM&A - Nuclear ($M)

Line No.	Division	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Nuclear Stations							
1	Darlington NGS	85.7	11.4	97.1	(13.9)	83.2	10.9	72.4
2	Pickering A NGS	41.0	1.0	42.1	(17.1)	25.0	(23.5)	48.5
3	Pickering B NGS	63.9	5.7	69.6	13.3	82.9	16.2	66.7
4	Pickering B Continued Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total Stations**	190.6	18.2	208.8	(17.7)	191.1	3.6	187.5
	Nuclear Support Divisions							
6	Engineering	1.0	0.6	1.6	(0.4)	1.2	0.2	1.0
7	Projects & Modifications	0.0	2.6	2.6	(0.8)	1.8	0.2	1.6
8	Facilities Management	0.1	(0.0)	0.0	0.0	0.1	0.0	0.1
9	Programs & Training	0.4	0.6	1.0	(0.4)	0.6	(0.1)	0.6
10	Supply Chain	1.5	0.2	1.6	(0.3)	1.3	(0.0)	1.3
11	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Inspection & Mtce Services[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Commercial Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Total Support**	2.9	3.9	6.8	(1.9)	5.0	0.3	4.6
16	**Total**	193.5	22.1	215.6	(19.5)	196.1	3.9	192.2

Notes:

1 Station costs include Inspection & Maintenance Services outage support.

Table 1b
Comparison of Outage OM&A - Nuclear ($M)

Line No.	Division	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
	Nuclear Stations					
1	Darlington NGS	83.2	26.5	109.8	38.0	71.8
2	Pickering A NGS	25.0	39.1	64.1	3.0	61.1
3	Pickering B NGS	82.9	(12.7)	70.2	(0.4)	70.5
4	Pickering B Continued Operations	0.0	2.8	2.8	2.8	0.0
5	**Total Stations**	191.1	55.7	246.8	43.4	203.4
	Nuclear Support Divisions					
6	Engineering	1.2	(0.2)	1.1	(0.0)	1.1
7	Projects & Modifications	1.8	1.1	2.9	1.4	1.6
8	Facilities Management	0.1	0.2	0.2	0.2	0.1
9	Programs & Training	0.6	0.4	1.0	0.6	0.4
10	Supply Chain	1.3	1.5	2.8	1.3	1.4
11	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0
12	Inspection & Mtce Services[1]	0.0	0.0	0.0	0.0	0.0
13	Commercial Services	0.0	0.0	0.0	0.0	0.0
14	Nuclear Level Common	0.0	0.0	0.0	0.0	0.0
15	**Total Support**	5.0	3.0	8.0	3.5	4.5
16	**Total**	196.1	58.7	254.8	46.9	207.9

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

Table 1c
Comparison of Outage OM&A - Nuclear ($M)

Line No.	Division	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Nuclear Stations							
1	Darlington NGS	109.8	(3.1)	106.7	(42.6)	64.2	(5.1)	59.0
2	Pickering A NGS	64.1	4.6	68.6	(16.7)	52.0	0.4	52.4
3	Pickering B NGS	70.2	20.4	90.5	(9.4)	81.1	(6.2)	74.9
4	Pickering B Continued Operations	2.8	(0.9)	1.9	11.0	13.0	(2.4)	10.6
5	**Total Stations**	246.8	21.0	267.8	(57.6)	210.2	(13.3)	196.9
	Nuclear Support Divisions							
6	Engineering	1.1	0.0	1.1	0.0	1.1	0.0	1.1
7	Projects & Modifications	2.9	0.1	3.1	(1.5)	1.5	(0.4)	1.1
8	Facilities Management	0.2	0.1	0.3	(0.2)	0.1	0.0	0.1
9	Programs & Training	1.0	(0.2)	0.8	(0.3)	0.5	0.0	0.5
10	Supply Chain	2.8	(1.2)	1.6	(0.2)	1.4	0.0	1.4
11	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Inspection & Mtce Services[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Commercial Services	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Nuclear Level Common	0.0	10.0	10.0	(10.0)	0.0	0.0	0.0
15	**Total Support**	8.0	8.9	16.8	(12.2)	4.6	(0.4)	4.2
16	**Total**	254.8	29.8	284.6	(69.9)	214.8	(13.7)	201.1

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

NUCLEAR FUEL COSTS

1.0 PURPOSE

This evidence describes OPG's nuclear fuel supply, sets out the forecast of nuclear fuel costs and identifies key cost drivers and assumptions.

2.0 OVERVIEW

The test period forecast for OM&A associated with nuclear fuel costs is $235.6M for 2011 and $261.7M for 2012, as set out in Ex. F2-T5-S1 Table 1. These costs form part of the requested nuclear revenue requirement.

This evidence also supports approvals related to the Nuclear Fuel Cost Variance Account which is described in Ex. H1-T1-S1.

Section 3.0 of this exhibit describes OPG's fuel supply objectives, strategies and processes and section 4.0 sets out the cost forecast for the test period, including an analysis of underlying trends affecting uranium pricing.

3.0 NUCLEAR FUEL SUPPLY

3.1 General

The accountability for developing supply strategies, executing procurement processes and administering nuclear fuel supply contracts rests with the Nuclear Supply Chain. OPG's nuclear fuel supply strategy is reviewed and approved by OPG senior management.

The nuclear fuel supply objectives and strategies are:

- High Quality: Fuel quality is assured by sourcing from suppliers that conform to the various Canadian Standards Association CAN3-Z299 quality standards. Supplier quality assurance program conformance is verified by OPG through source surveillance and audit.

- Security of Supply: OPG must ensure that its reactors are not shut down due to lack of fuel, and in that respect must ensure that each step in the supply chain is not substantially delayed due to lack of materials.
- Cost: OPG seeks to obtain supply at the lowest cost consistent with the above objectives.

OPG's nuclear fuel procurement strategies take into account new fuel requirements, existing inventories, existing supply arrangements and fuel supply market conditions.

OPG's standard procurement practice for nuclear fuel is to issue a request for proposals to a pre-determined group of suppliers, and to then evaluate proposals against pre-determined evaluation criteria that include quality, security of supply and costs. However, OPG may also review and accept unsolicited proposals on a case-by-case basis.

OPG's nuclear fuel supply chain is made up of the following stages:

- The purchase of uranium concentrate
- The purchase of services for the conversion of uranium concentrates to uranium dioxide
- The purchase of services for the manufacture of fuel bundles containing the uranium dioxide

OPG currently purchases each of these components separately and maintains ownership of the uranium throughout the supply chain. Nuclear fuel inventories are discussed at Ex. B1-T1-S1, section 3.2.3.

The CANDU fuel bundle is an integral assembly of hermetically sealed, zirconium clad, cylindrical fuel elements containing ceramic uranium dioxide pellets. Each Pickering reactor uses fuel bundles that have a 28-element configuration. Each Pickering A reactor (Units 1 and 4) has 390 fuel channels containing 12 fuel bundles each (4,680 bundles per reactor). Each Pickering B reactor (Units 5 through 8) has 380 fuel channels containing 12 fuel bundles each (4,560 bundles per reactor). Each Darlington reactor uses fuel bundles that have a 37-element configuration. Each Darlington reactor has 480 fuel channels containing 13 fuel bundles each (6,240 bundles per reactor).

3.2 Fuel Planning

OPG's fuel procurement planning begins with a forecast of fuel bundle reactor loading requirements. The quantity of fuel bundles required for normal fueling is determined by converting OPG's forecast of electrical energy production, as referenced at Ex. E2-T1-S1, into a forecast of fuel bundles required for fueling ("usage") using forecasts of fuel burn-up and reactor thermal efficiency rates ("fuel utilization efficiency").

OPG maintains inventories at each stage of the nuclear fuel supply chain. An inventory of fuel bundles equivalent to 12 months of expected forward usage is maintained to allow continued fueling in the event of a disruption in the supply of fuel bundles or uranium conversion. A working inventory of uranium dioxide is maintained to feed the fuel manufacturing process and an inventory of uranium concentrates and recycled uranium dioxide scrap from the manufacturing process is maintained to feed the production of uranium dioxide.

From the forecast of fuel bundle requirements, and with consideration of existing inventories, OPG can then determine its need for delivery of new manufactured fuel bundles, which in turn determines the need for uranium dioxide conversion services and then the need to procure and deliver new supplies of uranium concentrates.

The annual purchase quantities required to meet expected usage and inventory requirements over the 2010 - 2012 period are shown in Chart 1:

Chart 1
Annual Purchase Requirements for Usage and Inventory

Requirements (000's kgU)	2010	2011	2012	Total
Uranium Concentrates	720	786	813	2,319
Uranium Conversion	752	816	847	2,415
28-element Fuel Bundles	362	373	290	1,025
37-element Fuel Bundles	391	380	508	1,279

3.3 Fuel Bundle Manufacturing

A key objective in fuel bundle manufacturing is to ensure high quality. An improperly manufactured fuel bundle is at risk of failing within a reactor which would create additional costs to locate and remove the defective fuel bundle as well as to purify and decontaminate reactor systems. This could also potentially lead to reactor shutdown and an increased radiological risk. As such, OPG requires the fuel bundle manufacturer to maintain a quality program which conforms to the Canadian CAN3-Z299.1 to ensure that all phases, including design, procurement, manufacturing and inspection are appropriately controlled. OPG performs surveillance of all manufacturing processes and verifies conformance to quality standard CAN3-Z299.1.

OPG currently has a supply contract with one of the two domestic CANDU fuel bundle manufacturing suppliers which covers requirements through the test period. Most other countries using CANDU reactors have purchased or developed their own fuel bundle manufacturing capabilities. However these off-shore facilities are not qualified by OPG nor do they have capacity available to produce the 28-element and 37-element fuel designs required for OPG reactors. OPG's supplier has a well developed quality program and OPG has not had a manufacturing-related defect from this supplier in over 16 years.

Pricing under this contract is volume dependant and indexed to such factors as inflation and foreign exchange rates.

3.4 Uranium Conversion

The supplier's processes must conform to CAN3-Z299.2 to ensure that all phases, including procurement, manufacturing, and inspection, are appropriately controlled. OPG performs surveillance of the conversion process and verifies conformance to the quality standard.

OPG has a supply contract with the sole domestic supplier of uranium conversion services, which covers requirements through 2011. OPG expects that its new agreement for conversion services, beginning in 2012, will incorporate similar pricing as the existing agreement. OPG generally maintains a two to three month uranium dioxide working inventory and the supplier is also contractually required to maintain an inventory of certified uranium dioxide for OPG's use in the event of a supply interruption. Pricing under this contract is volume dependant and indexed to inflation.

3.5 Uranium Concentrates

3.5.1 Overview

OPG's strategy for ensuring a supply of uranium concentrates is to maintain a combination of supply contracts and inventory which provide a minimum of 100 per cent of delivery requirements for two years and a declining proportion of delivery requirements for ten years. OPG maintains a portfolio of uranium concentrates supply contract arrangements, diversified by source, contract term, and pricing mechanism. This diversity provides supply security, by ensuring that a supply disruption from any single supplier would not impact OPG's entire supply. Portfolio diversity also reduces cost volatility.

OPG's uranium concentrates requirements of 2,319,000 kgU are expected to be met over 2010 - 2012 through deliveries of 1,712,000 kgU under four existing contracts with three suppliers (74 per cent), the drawdown of 286,000 kgU of existing inventory (12 per cent), and new purchases of 321,000 kgU (14 per cent). New purchases will be made under long-term contracts, short-term spot market contracts, or a combination of both.

OPG's existing long term contracts for the supply of uranium concentrates contain a mix of pricing provisions. Under contracts with market-related pricing terms, quantities are priced at market price, established at or near the time of delivery. Contracts with indexed pricing include base prices, set at the time of contract signing, but which escalate to the time of delivery by formula or by published, inflation-related, indexes. The quantities of contract deliveries under the existing contracts are shown by year and by pricing category (market-related and indexed pricing) in Chart 2 below:

Chart 2
Existing Contracts by Pricing Category

	2010	2011	2012	Total
Market Related (000's kgU)	346	354	378	1,078
Indexed (000's kgU)	231	262	141	634
Total	577	616	519	1,712

The 321,000 kgU of new purchases (i.e., either under long-term or short-term spot market contracts) is priced at market prices forecast for 2010, 2011, and 2012.

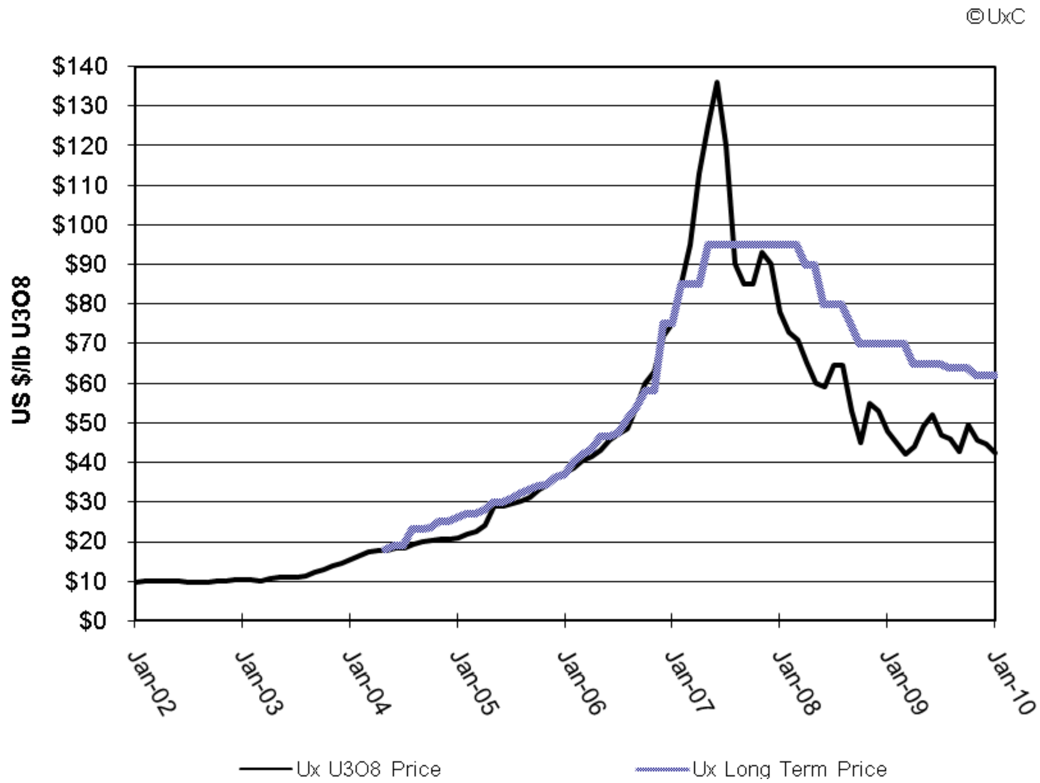
3.5.2 Market Conditions

Starting in 2003, demand for uranium began to increase in response to a number of factors, including: supply disruption events which highlighted the production risks (e.g., floods in Saskatchewan and Australian mines and a fire at an Australian mill), a renaissance of nuclear programs worldwide, particularly in Asia, and recognition of the limits to inventory reductions. These factors stimulated increases in the price of uranium and, as the price continued to rise, encouraged the entry of non-traditional market participants, such as investment funds. Uranium spot market prices peaked in June 2007 at US$136 per pound. Term prices, which are the starting prices for indexed price contracts, increased in parallel with spot prices through the first quarter of 2007, reaching a plateau of US$95 per pound. The majority of worldwide uranium purchases are provided under term contracts. The remainder is traded on the spot market, defined as having delivery within one year.

Since this peak, spot prices declined through 2008 and 2009, initially, due to a lack of utility demand and the credit crisis which forced the sale of investor-held uranium, and most recently, due to soft utility demand and a higher than planned amount of production available for sale. Term prices declined as well but not as low as spot prices, reflecting the longer-term supply/demand market fundamentals and the expected cost of new production. On the supply side, the price run-up initially stimulated significant exploration, investment in mine expansion and new uranium mining projects around the world. Recently, the drop in uranium prices and the credit crisis (i.e., reduced access to project funding) have meant that marginal mining projects have been dropped or deferred.

Historical spot market prices and term prices are shown in Figure 1.0.

Figure 1.0
Uranium Price Indicators



Based on industry forecasts, spot and term prices in the range of US$45 to US$80 per pound are expected over the test period. OPG used a mid price forecast of US$48 per pound in 2010 rising to US$61 per pound in 2012 in forecasting fuel costs. However, uncertainty in the schedules for new uranium production, liquidation of additional inventories, the pace of worldwide nuclear expansion, and political developments in uranium producing regions are expected to result in price volatility over the test period and account for a wide range of potential market prices.

4.0 NUCLEAR FUEL COST FORECAST

The nuclear fuel cost forecast for the calendar years 2011 and 2012 is shown in Ex. F2-T5-S1 Table 1 along with comparable figures for 2008, 2009 and 2010. The nuclear fuel costs as shown in Ex. F2-T5-S1 Table 1 represent the total cost of each finished fuel bundle in aggregate as it is loaded into a reactor.

The total cost of a finished fuel bundle as it is loaded into a reactor includes the cost of each of the three components (i.e., uranium concentrate, uranium conversion, and fuel bundle manufacturing). The relative weighting of the cost of the uranium concentrate to the total cost of the finished fuel bundle is expected to vary over time reflecting the underlying price volatility of uranium concentrates as discussed in section 3.5.2 above. This price volatility adds a great deal of uncertainty to forecasting future nuclear fuel costs. Given the expected volatility, OPG is proposing to continue the Nuclear Fuel Cost Variance Account. Over 2008 and 2009, uranium market prices were lower than those forecast by OPG in EB-2007-0905, resulting in a credit in the Nuclear Fuel Cost Variance Account (see Ex. H1 T1 S1 Table 1). OPG is forecasting a debit amount for 2010, such that overall there will be a net debit balance in this account owing to OPG from ratepayers for the period 2008 - 2010.

Exhibit F2-T5-S1 Table 1 also includes costs related to nuclear used fuel management services as discussed at Ex. C2-T1-S2, and fuel oil which is used to run stand-by generators.

As shown in Ex. F2-T5-S1 Table 1, OPG's nuclear fuel costs are trending higher over the period 2007 - 2012, despite uranium market (spot and term) prices having leveled off after spiking in 2007 (Figure 1.0). This disconnect between the trend in uranium market prices and the trend in nuclear fuel costs is primarily a reflection of the timing of OPG's negotiation of uranium concentrate contract prices, the expiry of previously negotiated supply contracts, fuel inventory management, and inventory accounting.

- Timing of OPG contract negotiations: There is a time lag between the time when uranium concentrate indexed contracts are negotiated (which reflect market conditions at the time of negotiation) and the time when the uranium concentrate is delivered into OPG's inventory. OPG's indexed priced contracts have base prices, set at the time of contract negotiation, which escalate to the time of delivery by formula or by published, inflation-related, indexes. Hence prices at time of delivery under such indexed price contracts do not reflect market prices at time of delivery, but rather market prices at the time the contract was entered into, plus escalation. For example, prices for indexed contracts negotiated in 2006 that are delivered in 2011 will reflect market prices in 2006, plus escalation, not 2011 spot or term market prices.

Chart 3 shows a summary of existing uranium concentrate supply contracts.

Chart 3

Summary of Existing Fuel Contracts (as of Dec 31, 2009)

Contract	Contract Negotiation	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing: MR = Market related COMB = combination of MR and Indexed
A	2006 1st half	2007	7 years	1,462	MR
B	2006 1st half	2010	6 years	1,154	COMB
C	2006 1st half	2011	5 years	385	COMB
D	2007 2nd half	2009	9 years	1,154	COMB

- Expiry of Existing Contracts. Fuel inventory during the period 2010 - 2012 includes uranium delivered prior to 2010 under contracts entered into by OPG during periods of lower uranium prices. While deliveries under these contracts will terminate prior to the test period, these deliveries being in inventory will beneficially impact nuclear fuel costs during the test period.

- Fuel Inventory Management: OPG maintains inventories at each stage of the nuclear fuel supply chain to ensure that supply disruptions do not impact on generation capability. OPG must ensure that its reactors are not shut down due to lack of fuel, and in that respect must ensure that each step in the supply chain is not substantially delayed due to lack of materials. As noted earlier, OPG's strategy for ensuring an available supply of uranium concentrates is to maintain a combination of supply contracts and inventory which provide a minimum of 100 per cent of delivery requirements for two years and a declining proportion of delivery requirements for ten years. For purposes of inventory management, OPG must regularly enter the uranium market for a portion of its supply needs regardless of prevailing uranium market prices.

- Average Cost Accounting: OPG uses average cost methodology for inventory accounting, which tends to smooth the impact of uranium concentrate price changes on nuclear fuel costs. There are lags between the time when uranium concentrate is delivered into OPG inventory, converted to uranium dioxide, placed into fuel bundles and loaded into a reactor. With average cost accounting, the price of uranium concentrate within a manufactured fuel bundle will lag changes in uranium market prices, e.g., average fuel costs may increase in a period when the market price of the uranium concentrate input is decreasing.

Attachment 1 shows a visual relationship between uranium concentrate market prices, OPG's contract prices at delivery and fuel bundle prices in inventory**.**

The key cost drivers impacting the year-over-year variances in nuclear fuel costs as shown in Ex. F2-T5-S1 Table 1 are:

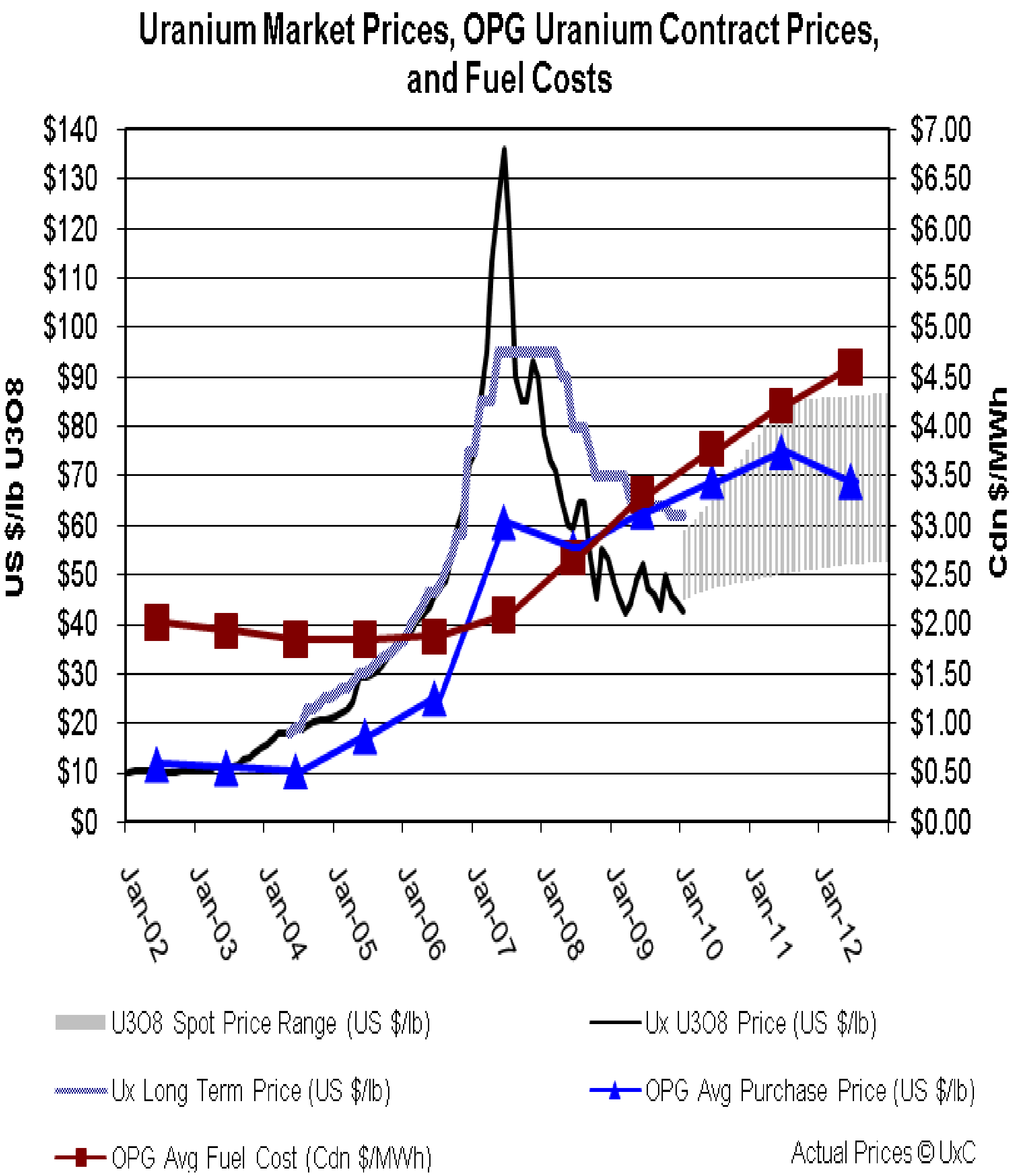
- Uranium concentrate price changes under market priced and indexed contracts
- Escalation of uranium conversion service and fuel bundle manufacturing contract prices at general inflation rates
- Changes in the level of OPG energy production
- Changes in fuel utilization efficiency

Explanations of nuclear fuel cost variances over the period 2007 - 2012 are more fully described at Ex. F2-T5-S2.

LIST OF ATTACHMENTS

Attachment 1: Uranium Market Prices, Uranium Contract Prices and Fuel Costs

1 **ATTACHMENT 1**



2

3 Note: OPG Average Purchase Price (US $/lb) relates to purchases within a given year.

Table 1
Nuclear Fuel Costs ($M)

Line No.	Prescribed Facility	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Uranium:						
1	**Darlington NGS**	57.5	78.4	87.9	102.6	117.9	128.0
2	**Pickering A NGS**	6.9	15.5	17.1	20.5	26.2	30.3
3	**Pickering B NGS**	27.9	34.6	49.9	50.5	61.2	71.1
4	**Total Fuel Bundle Cost**	92.3	128.4	154.9	173.6	205.3	229.3
5	**Total Fuel Bundle Cost[1] ($/MWh)**	2.09	2.67	3.31	3.76	4.20	4.59
6	**Used Fuel Storage & Disposal[2]**	16.4	19.0	19.2	23.0	26.6	28.5
7	**Fuel Oil**	4.3	2.5	(1.5)	5.3	3.8	3.9
8	**Total**	113.0	149.9	172.6	201.9	235.6	261.7

Notes:
1 Line 4 divided by Nuclear production forecast/actual from Ex. E2-T1-S1 Table 1.
2 Used Fuel Storage & Disposal is discussed in Ex. C2-T1-S2.

COMPARISON OF NUCLEAR FUEL COSTS

1.0 PURPOSE

This evidence presents period-over-period comparisons of nuclear fuel costs for 2007 - 2012.

2.0 OVERVIEW

This evidence supports the approvals sought for the nuclear fuel costs. Exhibit F2-T5-S2 Table 1 sets out the comparison of budget and actual nuclear fuel costs over 2007 - 2012. See Ex. F2-T5-S1 for a general discussion of key drivers associated with nuclear fuel costs.

3.0 PERIOD-OVER-PERIOD CHANGES - TEST PERIOD

<u>2012 Plan versus 2011 Plan</u>

The increase of $10.1M in nuclear fuel costs for Darlington is due to higher energy production ($0.6M) and to higher unit prices for the new fuel loaded into the units at the station ($9.5M).

The increase of $4.1M in nuclear fuel costs for Pickering A is due to higher energy production ($1.0M) and to higher unit prices for the new fuel loaded into the units at the station ($3.1M).

The increase of $9.9M in nuclear fuel costs for Pickering B is due to higher energy production ($3.0M) and to higher unit prices for the new fuel loaded into the units at the station ($6.9M).

<u>2011 Plan versus 2010 Budget</u>

The increase of $15.3M in nuclear fuel costs for Darlington is due to higher energy production ($4.2M) and to higher unit prices for the new fuel loaded into the units at the station ($11.1M).

The increase of $5.7M in nuclear fuel costs for Pickering A is due to higher energy production ($2.8M) and to higher unit prices for the new fuel loaded into the units at the station ($3.0M).

The increase of $10.6M in nuclear fuel costs for Pickering B is due to higher energy production ($3.3M) and to higher unit prices for the new fuel loaded into the units at the station ($7.3M).

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2010 Budget versus 2009 Actual

The increase of $14.7M in nuclear fuel costs for Darlington is due to higher energy production ($3.6M), higher unit prices for new fuel loaded ($10.1M), and lower fuel utilization efficiency ($1.0M).

The increase of $3.4M in nuclear fuel costs for Pickering A is due to higher energy production ($0.7M) and higher unit prices for new fuel loaded ($2.7M).

The increase of $0.6M in nuclear fuel costs for Pickering B is due to higher unit prices for new fuel loaded ($7.2M), partially offset by lower energy production (-$6.7M).

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS

2009 Actual versus 2009 Budget

The decrease of $10.3M in nuclear fuel costs for Darlington is due to lower energy production (-$1.9M), lower unit prices for new fuel loaded (-$7.8M), and higher fuel utilization efficiency (-$0.6M).

The decrease of $6.5M in nuclear fuel costs for Pickering A is due to lower energy production (-$5.3M) and lower unit prices for new fuel loaded (-$1.5M), partially offset by lower fuel utilization efficiency ($0.2M).

The decrease of $8.7M in nuclear fuel costs for Pickering B is due to lower energy production (-$3.5M) lower unit prices for new fuel loaded (-$5.0M) and higher fuel utilization efficiency (-$0.2M).

2009 Actual versus 2008 Actual

The increase of $9.5M in nuclear fuel costs for Darlington is due to higher unit prices for new fuel loaded ($16.7M) and lower fuel utilization efficiency ($0.5M), partially offset by lower energy production (-$7.7M).

The increase of $1.7M in nuclear fuel costs for Pickering A is due to higher unit prices for new fuel loaded ($3.0M) and lower fuel utilization efficiency ($0.4M), partially offset by lower energy production (-$1.8M).

The increase of $15.3M in nuclear fuel costs for Pickering B is due to higher energy production ($5.8M), higher unit prices for new fuel loaded ($9.4M).

2008 Actual versus 2008 Budget

The decrease of $0.6M in nuclear fuel costs for Darlington is due to higher fuel utilization efficiency (-$2.2M), partially offset by higher energy production ($0.8M) and by higher unit prices for the new fuel loaded into the units at the station ($0.8M).

The decrease of $1.6M in nuclear fuel costs for Pickering A is due to lower energy production (-$1.6M) and to higher fuel utilization efficiency (-$0.4M), partially offset by higher unit prices for the new fuel loaded into the units at the station ($0.4M).

The decrease of $8.5M in nuclear fuel costs for Pickering B is due to lower energy production (-$7.7M) and to lower unit prices for the new fuel loaded into the unit at the station (-$0.7M).

<u>2008 Actual versus 2007 Actual</u>

The increase of $20.9M in nuclear fuel costs for Darlington is due to higher energy production ($3.5M), higher unit prices for the new fuel loaded into the units at the station ($18.3M) partially offset by higher fuel utilization efficiency (-$0.9M).

The increase of $8.6M in nuclear fuel costs for Pickering A is due to higher energy production ($5.2M), higher unit prices for the new fuel loaded into the units at the station ($3.3M), partially offset by higher fuel utilization efficiency (-$0.5M).

The increase of $6.7M in nuclear fuel costs for Pickering B is due to higher unit prices for the new fuel loaded into units at the station ($7.2M) and lower fuel utilization efficiency ($0.5M), partially offset by lower energy production (-$1.0M).

<u>2007 Actual versus 2007 Budget</u>

The increase in nuclear fuel costs for Darlington is due to higher energy production ($0.9M) and to higher unit prices for the new fuel loaded into the units at the station ($2.5M).

The decrease in nuclear fuel costs for Pickering A is due to lower energy production (-$7.3M).

The decrease in nuclear fuel costs for Pickering B is due to lower energy production (-$4.8M) and to higher fuel utilization efficiency (-$1.3M).

Table 1
Comparison of Nuclear Fuel Costs ($M)

Line No.	Prescribed Facility	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Uranium:							
1	**Darlington NGS**	54.1	3.4	57.5	20.9	78.4	(0.6)	78.9
2	**Pickering A NGS**	14.2	(7.3)	6.9	8.6	15.5	(1.6)	17.0
3	**Pickering B NGS**	34.0	(6.1)	27.9	6.7	34.6	(8.5)	43.1
4	**Total Fuel Bundle Cost**	102.3	(10.0)	92.3	36.1	128.4	(10.6)	139.1
5	**Used Fuel Storage & Disposal**[1]	17.5	(1.1)	16.4	2.6	19.0	(1.6)	20.6
6	**Fuel Oil**	2.1	2.2	4.3	(1.8)	2.5	(0.2)	2.7
7	**Total**	121.8	(8.8)	113.0	36.9	149.9	(12.5)	162.4

Line No.	Prescribed Facility	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
	Uranium:					
8	**Darlington NGS**	78.4	9.5	87.9	(10.3)	98.2
9	**Pickering A NGS**	15.5	1.7	17.1	(6.5)	23.7
10	**Pickering B NGS**	34.6	15.3	49.9	(8.7)	58.6
11	**Total Fuel Bundle Cost**	128.4	26.5	154.9	(25.6)	180.4
12	**Used Fuel Storage & Disposal**[1]	19.0	0.3	19.2	(1.7)	20.9
13	**Fuel Oil**	2.5	(4.0)	(1.5)	(4.3)	2.8
14	**Total**	149.9	22.7	172.6	(31.5)	204.2

Line No.	Prescribed Facility	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Uranium:							
15	**Darlington NGS**	87.9	14.7	102.6	15.3	117.9	10.1	128.0
16	**Pickering A NGS**	17.1	3.4	20.5	5.7	26.2	4.1	30.3
17	**Pickering B NGS**	49.9	0.6	50.5	10.6	61.2	9.9	71.1
18	**Total Fuel Bundle Cost**	154.9	18.8	173.6	31.6	205.3	24.1	229.3
19	**Used Fuel Storage & Disposal**[1]	19.2	3.8	23.0	3.6	26.6	1.9	28.5
20	**Fuel Oil**	(1.5)	6.8	5.3	(1.5)	3.8	0.1	3.9
21	**Total**	172.6	29.3	201.9	33.7	235.6	26.1	261.7

Notes:
1 2008 Actual, 2009 Actual, 2010 Budget, 2011 Plan and 2012 Plan from Ex. C2-T1-S2 Table 1, line 4.
Used Fuel Storage & Disposal is discussed in Ex. C2-T1-S2.

OM&A PURCHASED SERVICES – NUCLEAR

1.0 PURPOSE

This evidence presents the purchases of OM&A services and products for the nuclear facilities that meet the threshold of one per cent of the OM&A expense before taxes consistent with the OEB filing guidelines.

2.0 OVERVIEW

This evidence supports the approval sought for nuclear OM&A costs. An overview of OPG's procurement process which is applicable to the nuclear facilities is presented in Ex. F3-T3-S1.

The nuclear OM&A expense before taxes is equal to the sum of nuclear base, project and outage OM&A. This sum ranges from $1,543.0M in 2011 to $1,553.2M in 2012 as presented in Ex. F2-T1-S1 Table 1. For the nuclear facilities the threshold of one per cent of the OM&A expense before taxes is therefore approximately $15M.

Information on vendor contracts for purchased services within the nuclear business that are equal to or in excess of the $15M threshold for the historical years, 2007, 2008 and 2009, is presented in Chart 1. The list includes ongoing services (e.g., Atomic Energy of Canada Limited) as well as limited duration, project-specific purchases (e.g., Ellis Don Fox Joint Venture, Duratek, AMEC Black & McDonald Joint Venture).

The $15M threshold has been applied broadly to include services that may also have been engaged for and applied against capital projects, the Decommissioning Fund, the Used Fuel Fund or other programs. If these non-OM&A expenditures were excluded from the annual totals in compiling Chart 1, there would be fewer reported vendors.

Total purchases for the vendors listed in Chart 1 are $298M in 2007, $335M in 2008 and $321M in 2009.

Chart 1
Purchase of Services - Nuclear Contracts

Vendor Name	Description/Nature of Activities	Tendering Process		Justification, if not Competitive
		Competitive	Single Source	
Acuren Group	Provider of augmented staff services related to non-destructive testing and other engineering testing.	X		
AMEC Black & McDonald Joint Venture	Pickering Auxiliary Power System Engineer, Procure, Construct (‘EPC’) contractor (primarily 2007, not ongoing)	X		
AREVA NP	Provider of engineering services, steam generator maintenance services and augmented staff.	X		

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Vendor Name	Description/Nature of Activities	Tendering Process		Justification, if not Competitive
		Competitive	Single Source	
Atomic Energy of Canada Ltd.	Provider of engineering services and original equipment manufacturer parts. Provider of feeder replacement services and tooling (in partnership with Babcock & Wilcox Canada Ltd.). Sourcing is a combination of competitive bid and single sourcing.	X	X	Work is competitively bid, except in instances where AECL is required to do the work as the original equipment manufacturer, or where AECL's proprietary knowledge is required for CANDU-related analysis.
Black & McDonald Ltd.	Provider of general construction services.	X		
Canadian Nuclear Safety Commission	Licensing fees, and licensing-related review costs.		X	Not applicable, as this is the nuclear regulator.

Vendor Name	Description/Nature of Activities	Tendering Process		Justification, if not Competitive
		Competitive	Single Source	
CANDU Owners Group Inc.	The CANDU Owners Group Inc. is a not-for-profit organization which provides programs for the support, development, operation and maintenance of CANDU reactor technology. All CANDU operators in the world are members of the CANDU Owners Group Inc.		X	Not applicable due to the nature of the services provided.
Duratek of Canada Ltd.	Service contract for resin liner remediation at Western Waste Management Facility	X		
Durham Regional Police	Provider of nuclear security services.		X	Services were provided by local police agency. OPG is transitioning to its own security forces.
Ellis Don Fox Joint Venture	Darlington Used Fuel Dry Storage Facility EPC contractor.	X		

Vendor Name	**Description/Nature of Activities**	**Tendering Process**		**Justification, if not Competitive**
		Competitive	**Single Source**	
Nuclear Safety Solutions Ltd.	Provider of engineering services, safety analysis services and specialized code development and maintenance. The majority of work was sole sourced; however, a small proportion of the work was competitively bid.	X	X	A mix of sole source and competitive bid. Nuclear safety analysis work is primarily sole source, reflecting their unique skill set in the marketplace.
Siemens Canada Ltd. Siemens Power Generation	Provider of maintenance and engineering services for Pickering turbines, as well as materials for overhaul of turbine-generator components.		X	Sole sourced since this is the original equipment manufacturer of the Pickering turbine generators.
Wardrop Engineering Inc.	Provider of engineering services. Majority of work competitively bid.	X	X	Occasionally single sourced for project continuity, where it is most cost-effective to do so. Internal processes are in place to monitor the extent and frequency of such instances.

DARLINGTON REFURBISHMENT AND NEW NUCLEAR AT DARLINGTON – OM&A

1.0 PURPOSE

This section identifies the OM&A costs associated with nuclear refurbishment projects and new nuclear at Darlington.

2.0 OVERVIEW

As discussed in the Base OM&A evidence (Ex. F2-T2-S1), there are several categories of OM&A funding in addition to Base OM&A. One such category is OM&A to support refurbishment and new nuclear at Darlington, a summary of which is provided in Ex. F2-T7-S1 Table 1 for 2007 - 2012.

The Darlington Refurbishment and new nuclear at Darlington projects are considered in detail in Ex. D2-T2-S1. Period over period OM&A comparisons for new nuclear at Darlington are provided in Ex. D2-T2-S1 section 3. There are also capital costs associated with Darlington Refurbishment and these costs are identified and described in Ex. D2-T2-S1 section 2.

Numbers may not add due to rounding.

Table 1
OM&A - Nuclear Generation Development ($M)

Line No.	Description	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(a)	(b)	(c)	(d)	(e)
	Darlington Refurbishment						
1	Darlington Refurbishment - Definition Phase	0.4	7.3	21.7	4.2	4.3	2.9
2	Darlington Campus Master Plan	0.0	0.0	0.0	1.3	1.6	1.6
3	**Total Refurbishment**	0.4	7.3	21.7	5.5	5.9	4.5
	New Nuclear Development						
4	Darlington New Nuclear	11.2	26.2	57.8	35.0	0.0	0.0
5	**Total New Nuclear Development**	11.2	26.2	57.8	35.0	0.0	0.0
	Legacy Organizations OM&A						
6	SVP Office (legacy)	0.1	0.0	0.0	0.0	0.0	0.0
7	New Generation Development (legacy)	0.0	0.6	0.0	0.0	0.0	0.0
8	**Total Legacy Organizations**	0.1	0.6	0.0	0.0	0.0	0.0
9	**Total Generation Development OM&A**	11.8	34.1	79.5	40.5	5.9	4.5