DETAILS OF OM&A PROJECTS – NUCLEAR

1.0 PURPOSE

This evidence provides project listings and supporting information, including business case summaries, for planned project OM&A expenditures for Nuclear Operations.

2.0 OVERVIEW

A tiered reporting structure consistent with the OEB filing guidelines has been used to present the evidence for all OM&A projects which have budgeted expenses during the test period.

- Tier 1 - Projects with a total cost of $20M or more. Summary level information is provided (see Ex. F2-3-3, Table 1) as well as business case summaries (Attachment 1 to this exhibit).
- Tier 2 - Projects with a total cost of $5M to $20M, for which summary level information is provided (see Ex. F2-3-3, Tables 2a and 2b).
- Tier 3 - Projects with a total cost of less than $5M, for which aggregated information is provided (see Ex. F2-3-3, Table 3).

For Tier 1 projects, Ex. F2-3-3 Table 1 provides information on eight released projects with a total project cost of $20M or more. These include four ongoing projects from EB-2013-0321, three completed projects, and one new project. Further details on these projects are provided in section 3.0.

For Tier 2 projects, Ex. F2-3-3 Tables 2a and 2b provide information on the 33 released projects with total project costs between $5M and $20M. These include nine ongoing projects from EB-2013-0321, seven completed projects from EB-2013-0321 and seventeen new projects. Total cost of these projects is $346.3M.

For Tier 3 projects, Ex. F2-3-3 Table 3 provides summary level information on the two projects with total project costs less than $5M. The average cost of these projects is $1.5M.

As per Ex. F2-3-3 Table 4, there are a total of 19 projects categorized as Project Portfolio (Unallocated). These projects are currently in the project identification or project definition phases, and detailed expenditure information by project is not available. OPG expects that by the test period, some of these listed projects (or other projects yet to be identified) would move from the project identification and initiation phases into project definition or execution phase as part of the ongoing portfolio management process. None of these projects are currently forecast to cost more than $20M.

3.0 PROJECT-SPECIFIC INFORMATION - TIER 1 PROJECTS

The following information relates to projects identified in Ex. F2-3-3 Table 1.

3.1 New Projects

One new Tier 1 project (#80067 Darlington Irradiated Fuel Bay Stacking Frame Replacement) has been undertaken since EB-2013-0321. The purpose of this project is to provide additional irradiated fuel storage space through the purchase of Long Stacking Frames. Long Stacking Frames are required to accommodate a new type of fuel bundle (Long Fuel Bundles) at Darlington which can not be stored in standard stacking frames. Darlington moved to a new fuel bundle to improve safety margins.

3.2 Completed Projects (from EB-2013-0321)

Three Tier 1 projects have been completed since EB-2013-0321.

Project #38457 Darlington EQ Components Replacement was completed under budget ($59.9M versus $63.1M). Project #62440 Probabilistic Risk Assessment Upgrade was also completed under budget ($50.1M versus $51.1M).

The total project cost for Project #40641 Pickering B Steam Generator Locking Tab Replacements A was $35.2M, an additional $14.7M over the full release issued in 2007 of $20.5M. The 2007 full release projected installation of divider plate locking tab devices on Units 7 and 8 by 2010. A supplementary release for $18.9M (including contingency) was approved in 2010 to complete the installation of the devices. The project was completed in

September 2012 at an additional cost of $14.7M. The primary reasons for the delay in installation and the subsequent cost variance are:

- Underestimation of the project execution costs ($4.8M)
- Remobilization costs to complete the project per the revised schedule ($4.0M)
- Radiological discovery issues ($2.8M)
- Costs to develop contingency tooling and installation ($2.7M)

Further detail on the project variances is provided in the #40641 Supplemental BCS included in Attachment 1 to this exhibit.

3.4 Project Cost Variances

There are no ongoing Tier 1 projects for which total forecast project cost variances currently exceed 10 per cent.

ATTACHMENTS

Attachment 1: Business Case Summaries for OM&A Projects of $20M or more

Note: Business Case Summaries included in Attachment 1 are marked “Confidential” or “Internal Use Only”, however, OPG has determined them to be non-confidential either in their entirety or with redactions as indicated.

Table 1 is a listing of Tier 1 OM&A projects with expenditures during the test period or Tier 1 projects completed/deferred from EB-2013-0321. The business case summaries for these projects are attached[1].

Table 1

Business Case Summaries

Tab No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date
		ONGOING PROJECTS FROM EB-2013-0321	
1	38933	Darlington Primary Heat Transport Liquid Relief Valve Modifications	Feb-14
2	62444	Fuel Channel Life Management	Oct-12
3	49248	Pickering A Locking Tabs - Boiler Divider Plate (Pickering 1 & Pickering 4)	Dec-11
4	80014	Fuel Channel Life Extension	Nov-13
		COMPLETED PROJECTS FROM EB-2013-0321	
5	38457	Darlington EQ Component Replacements	Jan-08
6	62440	Probabilistic Risk Assessment Upgrade	Apr-12
7	40641	Pickering B Steam Generator Locking Tab Replacement	Dec-10
		PROJECTS NOT IN EB-2013-0321	
8	80067	Irradiated Fuel Bay Stacking Frame Replacement	Dec-14

[1] OPG has requested confidential treatment of certain business case summaries under the OEB's Practice Direction for Confidential Information.

Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

Executive Summary and Recommendations				
Project #:	16-38933	**Title:**	DN PHT LRV Modifications (Waterhammer)	
Phase:	Execution		**Release:**	Partial
Facility:	Darlington		**Records File:**	D-BCS-63310-10004
Class:	OMA		**Investment Type:**	Regulatory

Project Overview

We recommend the release of $2,297 k [redacted] base costs plus [redacted] contingency).

This additional release will allow the completion of Detailed Engineering. Approval of this request will bring the total to date funding to $13,173 k including a contingency of [redacted] The total project is estimated to cost $25,758 k (including [redacted] contingency) with an estimated completion date of 12/23/2025.

The reason for this additional Partial Execution BCS is due to the added project scope that is required as a result of the re-design of the Liquid Relief Valve (LRV) from a bellows-sealed valve to a double-packed valve. The re-design was required in order to meet seismic qualification requirements and shorten the height of the valve for maintenance purposes. This change in valve design requires a drain line to be added for each installed valve. In addition, this change resulted in added scope to the Valve Vendor and Design Agency contracts.

The Business Objective of this Regulatory project is to address long term valve and piping degradation due to valve induced waterhammer, and ensure valve, piping and pipe support stresses are within allowable limits for design basis transients in which the Liquid Relief Valves (LRVs) operate. Replacement of the LRVs will mitigate rapid opening and closing times and eliminate waterhammer effects, while maintaining overpressure protection requirements. Continued operation has been justified via the Discovery Issue Resolution Process (DIRP) and subsequent Discovery Issue Assessment NK38-DIA-00531-10002 issued in 2006, which defined the nuclear safety risk associated with pipe failure as a result of LRV induced waterhammer. Routine LRV piping and support inspections during planned outages (supporting the DIRP) have been implemented to confirm structural integrity remains intact for continued operation of the Heat Transport System (HTS) until the replacement valves are installed.

Additionally the Engineering Decision Making (EDM) process was invoked in 2010 to reconfirm the conclusions of the DIRP for continued safe operation to further quantify the Darlington Nuclear Generating Station (DNGS) Site Management Board (SMB) decision to defer the installation of the LRVs concurrent with refurbishment due to economic, nuclear safety, and personnel dose concerns. The EDM Committee concluded it is technically acceptable to defer LRV replacement until the Darlington refurbishment outages with the issuance of a decision memorandum, NK38-CORR-33100-0362965 and technical memorandum, NK38-CORR-33100-0363511. The OPG decision to defer the installation phase concurrent with refurbishment has been accepted by the Canadian Nuclear Safety Commision (CNSC). As per memorandum, NK38-CORR-00531-15651, “CNSC’s staff concurrence is tied to the actual dates and therefore LRV replacement shall begin for the first unit during the first unit refurbishment outage or in 2016, whichever comes first. LRV replacement for the last unit shall begin during the last unit refurbishment outage or 2021, whichever comes first.”

The following deliverables will be completed during this release:

1. Continuation of design, test, and procure the new LRVs,
2. Completion of the Detailed Design by October 15, 2015, and
3. Preparation of the next Partial Execution Business Case Summary (BCS) for first unit installation in U2 Refurbishment.

The first unit Refurbishment outage will begin in Q4 2016, and the last unit Refurbishment outage is currently scheduled to finish by Q4 2025, with each Refurbishment outage spanning 3 years. Installation of the new LRVs will begin in the first unit Refurbishment outage (approximately starting April 2018) with project completion concurrent with completion of last unit Refurbishment outage (~2025).

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

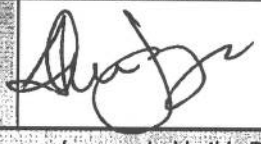
Type 3 Business Case Summary

Project Cash Flows									
k$	LTD	2013	2014	2015	2016	2017	2018	Future	Total
Currently Released	4,536	1,750	1,921	434	-	-	2,235	-	10,876
Requested Now	[redacted]	-	1,199	400	-	-	-	698	2,297
Future Required	[redacted]	-	-	-	-	218	1,715	10,652	12,585
Total Project Cost	4,536	1,750	3,120	834	-	218	3,950	11,350	25,758
Ongoing Costs	[redacted]	-	-	-	-	-	-	-	-
Grand Total	4,536	1,750	3,120	834	-	218	3,950	11,350	25,758

Estimate Class:	Class 3	**Estimate at Completion:**	[redacted]
NPV:	$ - 10,448 k	**OAR Approval Amount:**	$ 25,758 k

Additional Information on Project Cash Flows (optional):

Total estimated project cost is $ 25,758 k [redacted] base cost plus [redacted] contingency).

Approvals			
	Signature	**Comments**	**Date**
This BCS represents the best option to meet the validated business need in a cost effective manner.			
Recommended by: Glenn Jager Chief Nuclear Officer Project Sponsor			2014-1-17
I concur with the business decision as documented in this BCS.			
Finance Approval: Robin Heard Interim SVP and Chief Financial Officer			2014.2.3
I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Tom Mitchell President and CEO, per OAR 1.1			2014-02-05

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

Business Case Summary

Part A: Business Need

Business Need:

To ensure overpressure protection of the Heat Transport System (HTS) Darlington Nuclear Generating Station (DNGS) contains four 100% power actuated Liquid Relief Valves (LRVs) in each unit, two per loop sharing common piping. Each loop has been designed and instrumented for both valves to open simultaneously on high loop pressure.

During commissioning of Darlington, performance of the LRVs was identified as less than adequate. It was discovered that the opening force of the valve was only designed for zero power hot conditions, which was not adequate to overcome the operating conditions of the Primary Heat Transport (PHT) system at full power nor was the high flow rates due to the large differential pressure across the valve accounted for. Modifications were completed in two stages. This first stage involved installing larger tubing to allow more rapid depressurization of the air operated actuator to increase the valve opening speed. The second stage involved modification to the pilot plug and the pilot holes to provide larger flow capability and faster depressurization of the top of the main plug under hot conditions. The LRVs were also instrumented with displacement and force transducers to measure the valve stem movement and the actuator force. Following the changes, LRV performance was monitored to demonstrate availability and acceptable operation. Based on data recorded, Darlington LRVs are opening and closing faster than that assumed in the original design basis. This condition of fast opening/closing of the LRVs has the potential for higher than designed waterhammer load on the HTS piping.

In the event of an extremely rare set of circumstances occurring (i.e. design basis transients in which LRVs operate simultaneously), OPG is unable to definitively demonstrate that pipe and support stresses are within American Society of Mechanical Engineers (ASME) code allowable limits, as is required by the Operating License, and is therefore unable to prepare and certify an Analysis of Record. However, on-going inspection of the HTS piping system has found no sign of pipe or support degradation. Additionally, as required by N-PROC-RA-0094, a DIRP was used to define the nuclear safety risk associated with pipe failure as the result of LRV induced waterhammer. The DIRP assessment (NK38-DIA-00531-10002) concludes that continued operation of the units until the modifications are installed is acceptable because the risk of pipe failure remains very low and the consequences are bounded by the existing safety report.

In addition, the Engineering Decision Making (EDM) process was invoked in 2010 to reconfirm the conclusions of the DIRP for continued safe operation to further quantify the DNGS Site Management Board (SMB) decision to defer the installation of the LRVs concurrent with refurbishment due to economic, nuclear safety, and personnel dose concerns. The EDM Committee concluded it is technically acceptable to defer LRV replacement until the Darlington refurbishment outages with the issuance of a decision memorandum, NK38-CORR-33100-0362965 and technical memorandum, NK38-CORR-33100-0363511. The economic, nuclear safety, and personnel dose concerns are reduced significantly by completing installation and commissioning during refurbishment since the HTS will be drained. Specifically, the economic impact is in the range of $64M - $93M if this project was installed and commissioned during regular unit outages due to the estimated critical path extension impact, which is 46 (up to 66) days total. Furthermore, the SMB and EDM Committee agreed that design and procurement of the LRVs must be completed now (and not delayed any further) to mitigate the risk of potentially needing to advance the installation schedule if signs of pipe or support degradation is found during regularly scheduled inspections.

Type 3 Business Case Summary

Part B: Preferred Alternative

Description of Preferred Alternative: LRV Replacement

The adopted solution is to replace the existing LRVs with new LRVs which will address the valve opening and closing times to mitigate undesirable waterhammer effects while maintaining overpressure protection requirements. Based on operating experience (OPEX), demonstrated through modifications at Cernavoda B, Wolsung, and Quinshan, this will resolve the existing potential waterhammer problem associated with LRV operation. Additionally, the LRV warming line will be relocated. The present location of the warming line for the current LRV is too far away to maintain the fluid temperature upstream of the valve. Field measurement has indicated the fluid temperature at the inlet to the LRV is substantially lower than the design basis and as such the stainless steel to carbon steel weld upstream of the valve will be subjected to a much higher thermal transient when the LRV is lifted. This could lead to premature fatigue failure at the transition weld. The purpose of the relocation of the warming line is to reduce (as far as practicable) the local thermal fatiguing that is occurring near the LRV inlet due to geometry of the current warming line connection point, and the presence of the resulting cooler water dead leg. Qualification/performance testing of the new valve by an external vendor will be performed to confirm elimination of waterhammer due to valve operation.

In February 2009, OPG submitted the proposed two-part strategy to resolve the LRV waterhammer issue (NK38-CORR-0053-14465) to the CNSC, thus closing out REGM AR 28082043. Part 1 includes removal of the existing LRVs and local piping to the LRVs and replacement with new “flow to open” LRVs. Part 2 involves implementing an inspection process appropriately suited for on-going validation of the pressure boundary integrity of the existing HTS piping and supports. (Reference: NK38-CORR-00531-15055). After two rounds of correspondence requesting additional information and clarifications the CNSC responded in June 2010 that the CNSC agrees, in principle, to the proposed strategy. As per NK38-CORR-00531-15146, an Action Item 28116373 was opened to track the completion of OPG undertakings.

A Value Engineering session was conducted during the Conceptual Phase to identify a short list of key project strategies and associated risks. These strategies were later explored in greater detail to define the Preferred Alternative.

A total of sixteen (16) Nuclear Class 1 valve / actuator sets and commissioning spares will be purchased, and two (2) additional Non-Nuclear Class valves will be purchased and subjected to full qualification and performance testing. Since the removed valves will be highly contaminated and their remaining life difficult to quantify, the valves have no salvage value.

Major activities completed under the previous Developmental BCS and Partial BCS 1 Releases included the following:

1) Valve tendering specification was submitted and a budgetary estimate for valve procurement was received,
2) Preliminary design was completed and preliminary LRV opening/closing limits were established,
3) Valve design technical specification was issued,
4) Modeling, hydraulic/stress analysis Scope of Work was issued,
5) Two (2) Request For Proposals (RFPs) were issued and successful proponents selected for:
    a. Valve procurement, and
    b. Modeling, hydraulic and stress analysis.
6) 3rd Party Independent Technical Review of “Darlington Technical Position on Primary Heat Transport Liquid Relief Valve Piping was completed and report NK38-REP-33100-10028 issued, and
7) Measurements of the HTS piping associated with the waterhammer issues were collected from each unit during the DNGS Vacuum Building Outage (VBO).

Major activities completed ***thus far*** under the previous Partial BCS 2 Release for detailed design include the following:

1) Issued Major Contracts to successful proponents for:
    a. Valve Design and Procurement (Valve Vendor),
    b. Modeling, Hydraulic and Stress Analysis (Design Agency),
2) Phase I of Hydraulic and Stress Analysis by Design Agency,
3) Design and Manufacturing of two (2) non-nuclear class valves by Valve Vendor, and
4) Revised Overpressure Protection Report by Design Agency.

Major activities ***still remaining*** under the previous Partial BCS 2 Release for detailed design include the following:

1) OPG Projects Design Activities:
    a. Continuation of Design Agency deliverables review and acceptance,
    b. Continuation of Valve Vendor deliverables review and acceptance,
    c. Preparation of Design ECs (Mechanical, Civil, I&C),
    d. ASME Section XI Fatigue Analysis,
    e. Independent 3rd Party Design Review,
    f. CNSC Acceptance, and
    g. Technical Standards and Safety Authority (TSSA) Registration/Reconciliation.
2) Design Agency Contract Activities – Phase II Hydraulic & Stress Analysis and associated certified reports.
3) Valve Vendor Contract Activities:
    a. Qualification/seismic/performance testing of two (2) non-nuclear class valves,
    b. Completion of Final Thrust Calculations and all Nuclear Class 1 production valve documents, and
    c. Delivery of five (5) Nuclear Class 1 Valves and two (2) Commercial Test Valves for OPG Training Department.
4) Continuation of Project Management (Design Agency & Valve Vendor Contract Management, CNSC Updates).
5) Issuance of Work Request/RFP (including Scope of Work) and bid evaluations/negotiations for Procurement and Construction (PC) Contract for all four unit installations in Refurbishment outages.
6) Front End Planning, preparation of next Partial Execution BCS and Project Management Plan (PMP) for first unit installation.

Funding released by this Partial Execution BCS will allow the completion of the additional scope required in order to complete detailed design. The additional scope of work required and included under *this BCS* is summarized below:

1) Design Agency Contract Added Scope:
    a. Third Level Floor Response Spectrum to support Valve Seismic Testing,
    b. Supplementary Steel Qualification – Civil Structure,
    c. NF-3200 analysis on three (3) Post-type anchors using finite element analysis,
    d. NF-3000 analysis of sixteen (16) non-standard supports,
    e. Four (4) failing NB-3600 points that required NB-3200 analysis using finite element analysis,
    f. Analysis for one (1) extra non-standard support (base plate),
    g. Analysis for waterhammer generated by the Pressurizer,
    h. Stress analysis for four (4) new drain lines due to change in valve design,
    i. Material Reconciliation to support the use of ASME 2010 Code Effective Date (CED),
    j. Additional Scope due to "Parallel Approach" strategy to reduce impact on project schedule:
        i) Hydraulic Analysis based on the tested Coefficient of Flow (Cv) curve, and
        ii) Certified Letter for Stress Analysis Reconciliation after submission of validated and tested Cv curve.
2) Valve Vendor Contract Added Scope:
    a. Kalsi Valve & Actuator Program (KVAP) Calculations, and Side Load Analysis based on Test Data to support KVAP Calculations,
    b. Additional Valve Test at Wyle Facility requested by National Board,
    c. Additional Seismic Testing,
    d. Test Valve manufacturing re-work due to change in valve design (double-packed instead of bellows-sealed),
    e. Hydrotesting and Nameplating at Farris Facility, if requested by TSSA.
3) Hot Waterhammer Assessment by external contractor.

Future Execution BCS Releases will facilitate installation activities in four (4) Darlington units concurrent with refurbishment outages.

Based on operating experience (OPEX), valve replacement (with flow to open design) will reduce the waterhammer problem associated with the LRV operation to an acceptable level. This has been demonstrated through modification at Cernavoda B and installation of new valves at Wolsung and Quinshan. In addition to the OPEX on flow to open design, replacing the valve will also allow relocation of the warming line to keep the valve warm as postulated in the original design basis. The new valves/actuators will be ordered with reducers and piping spools attached to minimize installation time.

Type 3 Business Case Summary

Deliverables:	Associated Milestones (if any):	Target Date:
This Release:	*This Release:*	*This Release:*
Detailed Design Complete	Detailed Design Complete	15-Oct-2015
Future Releases:	*Future Releases:*	*Future Releases:*
Installation Labour Contracts Awarded	PC Contract Awarded	30-Mar-2016
U2 Work Planning Complete	U2 Start of Installation	29-Mar-2018
U2 Installation and Commissioning Complete	U2 Available for Service	03-Jul-2018
U1 Work Planning Complete	U1 Start of Installation	02-Mar-2021
U1 Installation and Commissioning Complete	U1 Available for Service	02-Jul-2021
U3 Work Planning Complete	U3 Start of Installation	05-Oct-2022
U3 Installation and Commissioning Complete	U3 Available for Service	06-Feb-2023
U4 Work Planning Complete	U4 Start of Installation	06-Mar-2024
U4 Installation and Commissioning Complete	U4 Available for Service	08-Jul-2024
Project Closure Report Complete	Project Plan Complete	23-Dec-2025

Part C: Other Alternatives

Base Case: Status Quo – No Project

This alternative is not recommended as OPG is unable to definitively demonstrate that pipe and support stresses are within ASME code allowable limits, as is required by the Operating License, and is therefore unable to prepare and certify an Analysis of Record. This does not satisfy the requirement for a long term solution to address operating outside of ASME code, as required by Discovery Issue Resolution Process (DIRP) N-PROC-RA-0094 Table 3, per the assessed conclusions of DIRP, NK38-DIA-00531-10002. Thus this option has not been financially evaluated.

Alternative 2: Delay Work – LRV Replacement

Installation is presently scheduled to start in Refurbishment (~Apr 2018). Delaying any further is not recommended since the possibility of a Heat Transport System (HTS) piping failure could increase, and the CNSC may direct OPG to take action to mitigate the waterhammer problem if a further delay is imposed. Thus this option has not been financially evaluated.

Alternative 3: Minor Modifications to the LRV/Actuator

This alternative is not recommended considering the minor modification will not completely eliminate the waterhammer problem. This is due to the fact that the present set up of the LRVs makes it difficult to control or to predict the valve behavior. Thus this option has not been financially evaluated.

Alternative 4: Reversal of Existing Valve Body and Replacement of Trim, Valve, Internals, and Actuator

This alternative is not recommended. Similar to the Recommended Option, OPEX indicates that reversal of the valve could correct the waterhammer problem. However, the existing valve internals, trim, and actuators would require replacement if the valves were reversed. Valve testing prior to installation is not possible. As a result, there are numerous uncertainties, reliability issues and a lack of confidence surrounding this option. Additionally, the remaining life of the valve bodies is difficult to quantify as they may have been subjected to waterhammer loads in the past. Thus this option has not been financially evaluated.

Alternative 5: Perform Analysis to Demonstrate Piping Integrity

After more than two years of analysis using both standard and non-standard methods of analysis, the piping designers concluded that the magnitude of waterhammer load in the event of an extremely rare set of circumstances occurring (under worst case scenario) would be unacceptably high and that stresses cannot be brought within ASME code allowable limits. Further analysis alone would not be beneficial. Therefore this is not a viable option. Thus this option has not been financially evaluated.

Alternative 6: Replace all Potentially Over-Stressed Piping in Conjunction with the Preferred Alternative, or Alternative 3 or 4

Replacement of all affected HTS piping has not been demonstrated to be necessary at this time. This option is not recommended since the cost of undertaking such a large replacement of the HTS piping would be extremely high and require extensive time to install. Thus this option has not been financially evaluated.

Type 3 Business Case Summary

Part D: Project Cash Flows

k$	LTD	2013	2014	2015	2016	2017	2018	Future	Total
Currently Released	4,536	1,750	1,921	434	-	-	2,235	-	10,876
Requested Now	-	-	1,199	400	-	-	-	698	2,297
Future Required	-	-	-	-	-	218	1,715	10,652	12,585
Total Project Cost	4,536	1,750	3,120	834	-	218	3,950	11,350	25,758
Ongoing Costs	-	-	-	-	-	-	-	-	-
Grand Total	4,536	1,750	3,120	834	-	218	3,950	11,350	25,758

Estimate Class:	Class 3	**Estimate at Completion:**	[redacted]	**OAR Approval Amount:**	$ 25,758 k

Additional Information on Project Cash Flows (optional):

Total estimated project cost is $ 25,758 k[redacted] base cost plus[redacted] contingency).

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case	Delay Work	Alternative 3	Alternative 4
Project Cost	25,758	N/A	N/A	N/A	N/A
NPV (after tax)	- 10,448	N/A	N/A	N/A	N/A
N/A	N/A	N/A	N/A	N/A	N/A

Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):

As per OPG-STD-0076, an economic justification is not required for Regulatory Projects.

Part F: Qualitative Factors

The successful completion of this project will address the following:

1) Establish acceptable limits for LRV opening and closing operation.
2) Confirm that valve operation effectively reduces waterhammer and stresses to acceptable levels.
3) Maintain Station Operating License.
4) Satisfy Regulatory issues.
5) Decrease risk of piping failure.
6) Decrease the rate of equipment aging due to fatigue which could potentially impact on plant life extension.

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	If the valve Cv curve from testing is different than the predicted Cv curve, the Design Agency will have to rework all the stress analysis.	1. Reassurance was obtained from the Valve Vendor that the predicted Cv curve provided is bounding. 2. Design Agency will verify that the validated Cv curve provided by Valve Vendor after testing is acceptable by re-running the hydraulic analysis only.	Low	Medium
Scope	External stakeholders (TSSA, CNSC) requests ASME Section III analysis (instead of ASME Section XI analysis), which results in replacement of all affected PHT piping.	1. A concession from the CNSC to invoke ASME Section XI analysis instead of ASME Section III analysis has been obtained to finalize the detailed design.	Low	High
Schedule	OPG Detailed Design and/or Stress Analysis takes longer than anticipated to complete. Specific factors which may contribute to this are additional failure nodes identified during stress analysis, changes to the technical specifications, and/or valve re-design required due to seismic qualification issues.	1. Ensured resourcing and schedule durations provided are agreed to by support groups, Valve Vendor, and Design Agency. 2. Expedite any required Valve Vendor and Design Agency information or deliverables. 3. Coordinate schedule between OPG, Valve Vendor, and Design Agency to meet Design milestones.	Medium	Medium
Resources	Lack of Designers & Analysts with extensive Nuclear Class 1 experience, Engineering Mechanics Department (EMD) Modeling Experience, Nozzle re-qualfication, and/or Section XI analysis. Impact includes review of stress analysis reports, which can take longer than originally anticipated by EMD.	1. Modeling and Stress/Hydraulic Analysis was contracted out to an External Design Agency with extensive knowledge to support OPG throughout Detailed Design. 2. Obtained committment from EMD for review of Design Agency Deliverables, nozzle qualification, and Section XI analysis.	Low	Medium
Quality/ Performance	Test Valve fails seismic shaker table test when attempting to qualify the Valve to the owner-generated Floor Response Spectrum (FRS).	1. Assurance obtained from Valve Vendor that the test valve can be seismically qualified to the owner-generated FRS.	Low	Medium
Technical	If ASME Section XI Appendix L analysis results in an inspection frequency that's too high, then additional detailed analysis will be required which may delay the project schedule.	1. Section XI Appendix L analysis for Phase I data will be performed now in order to obtain a draft inspection frequency number. 2. Specific contigency alloted for this risk.	Low	Medium

Schedule	CNSC and/or TSSA approvals for the modification may take longer than expected.	1. The Project will ensure CNSC and/or TSSA acceptance requests are submitted with sufficient time for approval.	Medium	Medium
Regulatory	If the Refurbishment Outage for Unit 2 does not start by Q4 2016 as committed by OPG to the CNSC (Reference: NK38-CORR-00531-15651), then a forced outage in 2016 will be required in order to install the new LRVs.	1. Continuously follow up with Refurbishment Organization to ensure U2 Refurbishment Outage is still on track for Q4 2016 per CNSC Action Tracking Assignments.	Low	High
Scope/Cost	As the piping Design Specification is not certified yet, the scope of the contract with the Design Agency may change causing rework, additional analysis effort, and schedule delays.	1. OPG Senior Management support was obtained in order to assign a certifier for the Piping Design Specification. 2. Commitment obtained from Design Engineer to certify Design Specification by March 2014. 3. OPG Senior Management agreed that the Design Agency can progress with the stress analysis work at risk to reduce impact on project schedule.	Low	Medium
Schedule	Valve Testing or Valve Vendor contract deliverables are not submitted / completed as per schedule and/or initial test results may not meet code standards or technical requirements.	1. Expedite submission of Valve Vendor Deliverables, and OPG review and acceptance turnaround times. 2. Continuously monitor valve testing schedule with Vendor until testing begins successfully. 3. Expedite and monitor valve testing once started.	Medium	Medium

Additional Risk Analysis:

Refer to Risk Management Plan within the Project Management Plan (NK38-PLAN-63310-0481548) for full risk analysis using the Moderate Risk Management strategy.

Part H: Post Implementation Review (PIR) Plan

Type of PIR	Target Project In Service Date	Target PIR Completion Date
Simplified	2024-07-08	2025-12-23

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Acceptable LRV opening and closing limits established.	Current opening / closing time is < 0.05 seconds	Opening / closing times between 1.0-3.0 seconds	Through valve/actuator testing and commissioning following each unit's installation	Vendor / Contractor / Maintenance

Confirm by analysis that valve operation effectively reduces waterhammer to acceptable levels under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions.	Cannot be demonstrated that piping meets ASME Section III stress and fatigue limits under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions.	Perform ASME Section XI flaw tolerance evaluation to demonstrate piping condition is acceptable under all design basis events for which the LRVs are called to operate, with consideration to the full range of design and operating conditions.	Hydraulic and Stress Analysis modeling to be used as input into Section XI analysis, to be completed during Detailed Design Phase.	Design Agency / OPG Engineering Services / Projects Design
Outage inspections of piping and support.	Piping and supports are inspected every planned outage.	Reduce number of inspections to every 2nd or 3rd planned outage per inspection.	Reduced inspection frequency as derived by Engineering Services per ASME Section XI.	OPG Engineering Services / Projects Design
Relocation of LRV warming line to mitigate large temperature gradient (as high as 80°C) condition upstream of LRVs due to stagnant fluid.	Current LRV warming line is located on the vertical run of pipe upstream of the LRVs. Due to this configuration, a portion of fluid immediately upstream of the LRVs remains stagnant and cools due to natural convection.	By relocating LRV warming line closer to LRVs with the connection to the horizontal run, fluid will circulate this dead leg region and ensure temperature gradient does not develop.	Temperature will be measured immediately upstream of the LRV inlet and compared with temperature measured at a location further upstream. Temperature measurements are expected to be within 20°C.	Vendor / Contractor / Maintenance

Part I: Definitions and Acronyms

ASME	American Society of Mechanical Engineers
BCS	Business Case Summary
CED	Code Effective Date
CNSC	Canadian Nuclear Safety Commission
Cv	Coefficient of Flow
DIRP	Discovery Issue Resolution Process
DNGS	Darlington Nuclear Generating Station
EDM	Engineering Decision Meeting
EMD	Engineering Mechanics Department
ES	Engineering Services
FRS	Floor Response Spectrum
HT	Heat Transport
HTS	Heat transport System
ITP	Inspection and Test Plan
KVAP	Kalsi Valve & Actuator Program
LRV	Liquid Relief Valve
OPEX	Operating Experience
OPG	Ontario Power Generation
PC	Procurement and Construction
PHT	Primary Heat Transport
PMP	Project Management Plan
REGM	Regulatory Management
RFP	Request for Proposal
SMB	Site Management Board
SOW	Scope of Work
TBD	To Be Determined
TSSA	Technical Standards and Safety Authority
VBO	Vacuum Building Outage

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For Internal Project Cost Control

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Appendix A: Summary of Estimate										
Project Number:	16-38933		Facility:	Darlington						
Project Title:	DN PHT LRV Modifications (Waterhammer)									
Estimated Cost in k$										
	LTD	2013	2014	2015	2016	2017	2018	Future	Total	%
OPG Project Management	637	41	198	240	-	188	188	1,128	**2,620**	10
OPG Engineering	1,156	150	293	231	-	-	81	247	**2,158**	8
Permanent Materials	974	82	310	187	-	-	2,435	4,919	**8,907**	35
Design and Construction	[redacted]									
Consultants										
Other Contracts/Costs										
Interest										
Subtotal										
Contingency										
Total	4,536	1,750	3,120	834	-	218	3,950	11,350	25,758	
Removal Costs Included	-	-	-	-	-	-	-	-	-	0

Notes			
Project Start Date	2008-12-17	Project Completion or In-Service Date	2025-12-23
Interest Rate	N/A %	Escalation Rate	2 %
Definition Cost Included	$7,984 k	Estimate at Completion	[redacted]

Prepared by:	Approved by:
Ricardo Fiorini Section Manager Darlington Projects 2013-12-18 YYYY-MM-DD	Dragan Popovic Director Darlington Projects 2013-12-19 YYYY-MM-DD

Type 3 Business Case Summary

Appendix B: Comparison of Total Project Estimates

Phase	Release	Date (YYYY-MM-DD)	Total Project Estimate in k$ (by year including contingency)						Later	Total Project Estimate
			2012	2013	2014	2015	2016	2017		
Initiation	Developmental	2008-12-08	5,826	6,966	3,606	-	-	-	-	16,398
Definition	Partial	2009-10-26	5,772	5,682	2,989	-	-	-	-	14,443
Execution	Partial	2011-07-08	5,037	2,873	-	333	-	2,633	10,733	21,609
Execution	Partial	2014-01-22	4,536	1,750	3,120	834	-	218	15,300	25,758

Project Variance Analysis

Estimated Cost in k$

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management	637	3,056	2,620	(436)	OPG Project Management costs were overestimated in last BCS.
OPG Engineering	1,156	2,655	2,158	(497)	OPG Engineering costs were overestimated in last BCS.
Permanent Materials	973	6,744	8,907	2,163	Cost of valve procurement and testing increased due to several added scope items (see Part B of this BCS for detailed list). Also, cost of materials for new drain lines (qty 16) have been added.
Design and Construction	[redacted]				
Consultants					
Other Contracts/Costs					
Interest					
Subtotal					
Contingency					
Total	**4,536**	**21,609**	**25,758**	**4,149**	
Removal Costs Included	-	-	-	-	-

Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

Project Cost:

None.

Financial:

(1) A financial evaluation is not required as per OPG-STD-0076 for Regulatory Projects.

Project Life:

(1) The LRVs will be replaced during Refurbishment Outages.

Energy Production:

None.

Operating Cost:

None.

Other:

None.

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

A financial evaluation is not required as per OPG-STD-0076 for Regulatory Projects.

Appendix D: References

1) NK38-MDR-33100-10002 – Modification Design Requirements
2) NK38-PLAN-63310-0481548 – Project Management Plan
3) D-PCH-63310-10001 – Project Charter
4) D-BCS-63310-10001 – Developmental BCS
5) D-BCS-63310-10002 – Partial BCS 1
6) D-BCS-63310-10003 – Partial BCS 2

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Type 3 Business Case Summary

Final Security Classification of the BCS: **Internal Use Only**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

Executive Summary and Recommendations				
Project #:	10-62444 (OM&A), 28-66567 (Capital)	**Title:**	Fuel Channel Life Management Project (OM&A) & Annulus Spacer Retrieval Tool Project (Capital)	
Phase:	Definition and Execution		**Release:**	Full
Facility:	Nuclear		**Records File:**	N-BCS-31100-10008
Class:	Capital and OMA		**Investment Type:**	Sustaining

Project Overview

We recommend the release of $22.4 M ($17.9 M base costs plus $4.5 M contingency).

This request is for OM&A funding for the completion of the Fuel Channel Life Management (FCLM) Project. The Annulus Spacer Retrieval Tool (ASRT) Project will be closed out in December 2012 and does not require additional funding. The total project cost, including previous expenditures, is forecast to be $55.2M.

The work scope of the FCLM project under this release includes:

1) **DISCOVERY WORK**: Conduct additional testing and modelling to address discovery issues related to pressure tube fracture toughness and annulus spacer embrittlement.
2) **R&D SCOPE CONTINUANCE**: Complete work on the current CANDU Owners Group (COG) research and development (R&D) joint project in the areas of crack initiation and probabilistic core assessments.
3) **REGULATORY REQUESTS**:
   - Pilot the High Flux Isotope Reactor (HFIR) sub-project aimed to systematically study the irradiation effects on annulus spacers. The post-pilot phase will be funded by COG Fuel Channel R&D funding to 2020.
   - Manage the development of a guideline for annulus spacer Fitness-for-Service through COG, for future incorporation into Canadian Standards Association (CSA) standards.
4) **THIRD PARTY REVIEWS:** Obtain third party reviews on technical submissions to the Canadian Nuclear Safety Commission (CNSC) to enhance regulatory confidence
5) **DEMONSTRATE MARGIN ON FRACTURE TOUGHNESS FOR TARGETED SERVICE LIFE:** Further development of an alternative hydriding method to conduct high hydrogen equivalent concentration burst tests and other studies to demonstrate additional available margin on fracture toughness for current targeted service life for both Pickering and Darlington units.

OTHER PROJECT TASKS:

6) Continue technical submissions to the CNSC to demonstrate continued fitness-for-service of fuel channel components.
7) Integrate R&D results into Life Cycle Management plans, Pickering's Continued Operations plans and Darlington's Refurbishment plans.
8) Close out project by June 2015.

FUNDING HISTORY:

- Three partial releases have been approved to date. Of a released-to-date of $37.5M, $32.8M is estimated as the life-to-date total by December 2012. The release-to-date amount is estimated to be underspent due to unused contingency and underspending of the approved budget.
- The ASRT project (Capital) will be declared in service by October 2012, and will be closed out in December 2012.

CONFIDENCE OF ESTIMATE:

The cost estimate is classified as an AACE Class 2 estimate since most of the R&D scope and regulatory submission scope has been defined and documented. However, there are uncertainties with regards to the cost and scope of discovery work. A conceptual estimate has been received for the HFIR sub-project. A detailed estimate will be produced by the vendor by December 2012. Therefore, the expected accuracy range of the estimate is -15% to +25%. Based on the risks identified in the remaining project scope of work, a 25% contingency value has been

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

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included to this release.

PROJECT TIMING REQUIREMENT:
The continuance of this project is critical as the results are key inputs to the continued assessment of the fitness-for-service of fuel channel components to the end of targeted service life. These results have a direct impact on the technical and schedule aspects of the Pickering Continued Operations and Darlington Refurbishment. The FCLM project will be closed out by June 2015.

Project Cash Flows

k$	LTD	2011	2012	2013	2014	2015	2016	Future	Total
Currently Released	8,172	10,570	14,074						32,816
Requested Now	-			15,687	6,274	459			22,420
Future Required	-								
Total Project Cost	8,172	10,570	14,074	15,687	6,274	459			55,236
Ongoing Costs	-								
Grand Total	8,172	10,570	14,074	15,687	6,274	459			55,236

Estimate Class:	Class 2	**Estimate at Completion:**	$55,236 k
NPV:	$1,500 M	**OAR Approval Amount:**	$55,236 k

Additional Information on Project Cash Flows (optional):

The "Currently Released" figures in 2011 and 2012 reflect the summation of the originally released amounts and the adjustments due to approved budget underspending and unused contingency. The 2011 originally released amount and adjustment are $13,769k and $(3,199)k, respectively. The 2012 originally released amount and adjustment are $15,548k and $(1,474)k, respectively. The Total "Currently Released" column reflects these adjustments as well.

The ASRT (capital) project will be closed in Dec 2012. No additional funding is required.

Approvals

	Signature	Comments	Date
This BCS represents the best option to meet the validated business need in a cost effective manner.			
Recommended by: Mark Elliott, SVP Nuclear Engineering & Chief Nuclear Engineer Project Sponsor			Sept 24, 2012
I concur with the business decision as documented in this BCS.			
Finance Approval: Donn Hanbidge, SVP & Chief Financial Officer Position per OPG-STD-0076			Oct 11/12
I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Tom Mitchell, President & Chief Executive Officer Position per OAR, per OAR 1.1			Oct 12/12

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Final Security Classification of the BCS: **Internal Use Only**

Business Case Summary

Part A: Business Need

Business Need:

BUSINESS DRIVER and PROJECT OBJECTIVES:

As CANDU reactors age, OPG needs to determine the impact of degradation mechanisms on fuel channel components. These degradation mechanisms may impact OPG's ability to demonstrate fitness-for-service of the units and, consequently, the success in continuing to operate the Pickering units to 247,000 Equivalent Full Power Hours (EFPH) and the Darlington units to 210,000 EFPH prior to refurbishment. The R&D work to investigate these degradation mechanisms is categorized as follows:

1) Effect of Hydrogen/Deuterium ingress on pressure tube fracture toughness
2) Pressure tube crack initiation by delayed hydride cracking (DHC), fatigue or overload
3) Mobility and integrity of annulus spacers and prevention of pressure tube/calandria tube contact

The methodologies for conducting Probabilistic Core Assessments (PCA), Leak-Before-Break (LBB) assessments, and demonstration of Fracture Protection are also being updated with input from the above areas.

The project scope includes managing R&D in the above areas, analyzing and communicating results to interdependent projects and organizations, as well as providing evidence to the Canadian Nuclear Safety Commission (CNSC) that OPG is engaged in safely operating its units through to the targeted service life. The work successfully completed by this project since 2009 will enable the provision of a high confidence statement on the operating life spans of fuel channels at the Pickering and Darlington units to the Board of Directors, on both the technical and regulatory fronts.

PROGRESS TO DATE:

Major Deliverables Completed:

FRACTURE TOUGHNESS

- Updated engineering fracture toughness curves based on R&D findings that will guide the practical adjustment of site-specific operating envelopes toward the end of targeted service life.
- Thirteen burst tests on pressure tubes hydrided at between 65 and 111 ppm hydrogen equivalent ([Heq]) concentration using the standard electrolytic hydriding method.

CRACK INITIATION

- Completed tests using more realistic sample geometries and conditioning cycles to quantify increased crack initiation resistance. Reporting of the technical basis of the new models to the CNSC is due in 2013.

SPACERS

- Conducted crush testing of Inconel X-750 spacers using newly-designed flat platen annulus spacer crush test rig.
- Designed, constructed and commissioned annulus spacer fatigue test rig.
- Completed assessments of mobility and integrity for Inconel X-750 annulus spacers (tight fitting type) and Zr-Nb-Cu annulus spacers (loose fitting type).
- Submission of the "Long Term Darlington Life Management Plan for Inconel X-750 Annulus Spacers" to CNSC. This is a living plan detailing OPG's strategy to quantify and project the impact of degradation mechanisms on Inconel X-750 annulus spacers, and to monitor the condition of in-service spacers at Darlington.

PROBABILISTIC CORE ASSESSMENT / LEAK-BEFORE-BREAK

- Improved methodologies for the Probabilistic Core Assessment tool were developed to reflect the current understanding of fuel channel degradation and to offer a more realistic assessment of reactor core integrity. Reporting of the technical basis of the new models to the CNSC is due in 2013.
- Development of probabilistic approaches to demonstrate Leak-Before-Break and Fracture Protection has been initiated. These new approaches will provide more realistic assessments over the current deterministic approaches.

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CNSC INTERFACE

An agreement with the CNSC was reached regarding the work required to support the operation of Pickering and Darlington units, and the process for submitting findings to the regulator. This agreement was formalized in the Protocol document. CNSC staff issued specific Closure Criteria to help OPG meet the requirements of the Protocol. OPG has met all submission requirements, including the following key submissions:

- Protocol Submission 14: Zr-Nb-Cu Spacers – Integrity – Assessment Spacer Integrity
- Protocol Submission 16: Inconel X-750 Spacers – Mobility – Assessment of Spacer Mobility
- Protocol Submission 17: Inconel X-750 Spacers – Integrity – Assessment of Spacer Integrity
- Protocol Submission 18: Fracture Toughness – Final Assessment of Fracture Toughness Data

OPG has also submitted to the CNSC long term fuel channel life management plans for Pickering and Darlington sites. A favourable reply for Pickering has been received. Response to the Darlington plan is pending.

PROJECT SCOPE under this BCS:

1) **DISCOVERY WORK**: Conduct additional testing and modelling to address discovery issues related to pressure tube fracture toughness and annulus spacer embrittlement.
   - In the area of pressure tube fracture toughness, additional testing and data modeling is required to validate the proposed new fracture toughness model for higher hydrogen contents, and to refine the understanding at the lower temperature regime for practical heat-up and cool down procedures.
   - In the area of annulus spacers, the rate of degradation caused by newly discovered degradation mechanisms (i.e. transmutation of nickel into helium, causing helium voids) must be established. This information is required to enable continued demonstration of fuel channel fitness-for-service until the Darlington units are ready for refurbishment.

2) **R&D SCOPE CONTINUANCE**: Complete work on the current CANDU Owners Group (COG) R&D joint project in the areas of crack initiation and probabilistic core assessments.

3) **REGULATORY REQUESTS**:
   - As part of the Closure Criteria, the CNSC requires OPG to test additional spacer material (in addition to material obtained through planned periodic inspection of pressure tubes) obtained by Single Fuel Channel Replacement (SFCR), through off-shore CANDU units, or from an accelerated test reactor. A test program using the HFIR (High Flux Isotope Reactor) reactor at Oak Ridge National Laboratory (ORNL) is being developed to satisfy this criterion and provide a predictive capability regarding material property degradation. The HFIR reactor has a flux spectrum that closely resembles the CANDU flux spectrum, but a higher flux rate which allows the reactor to replicate 25 years of irradiation damage in less than 7 years. This project is responsible for reactor set up, material procurement, and the shipping and testing of the samples removed at the first interval.
   - At present, CSA does not specify performance requirements for annulus spacers. The CNSC has requested the development of a guideline for annulus spacer Fitness-for-Service through COG, for future incorporation into CSA standards.

4) **THIRD PARTY REVIEWS:** Obtain third party reviews on technical submissions to the CNSC to enhance regulatory confidence.

5) **DEMONSTRATE MARGIN ON FRACTURE TOUGHNESS FOR TARGETED SERVICE LIFE:** : Further development of an alternative hydriding method to conduct high hydrogen equivalent concentration burst tests and other studies to demonstrate additional available margin on fracture toughness for current targeted service life for both Pickering and Darlington units.

OTHER PROJECT TASKS:

6) Continue technical submissions to the CNSC to demonstrate continued fitness-for-service of fuel channel components.
7) Integrate R&D results into Life Cycle Management plans, Pickering's Continued Operations plans and Darlington's refurbishment plans.
8) Close out project by June 2015.

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The project close out date is June 30, 2015.

BUSINESS COMMITMENT TO WORK BEYOND PROJECT COMPLETION

Fuel channel management plans for Pickering and Darlington units have been submitted to the CNSC. The Darlington plan also includes the "Long Term Darlington Life Management Plan for Inconel X-750 Annulus Spacers". These plans specify R&D, inspection, and material surveillance activities that extend beyond the scope and timeline of this project. These activities should be regarded as commitments to the CNSC. The inspection and material surveillance commitments are documented in station unit specific Life Cycle Management Plans (LCMP). The R&D work is described in the scope of this BCS.

It should be noted that the "Long Term Darlington Life Management Plan for Inconel X-750 Annulus Spacers" is described as a living plan due to limited information available. This means that there are hold points specified in the plan when an update of the plan is required, based on information available at the time.

INVESTMENT HISTORY:

For the FCLM project, three partial releases have been approved to date, with a release-to-date of $34.4M. The estimated life-to-date spent by December 2012 is $31.6M.

For the ASRT project, two partial releases have been approved to date, with a release-to-date of $3.1M and a project life-to-date spent of $1.2M. This project will be closed out in December 2012.

Thus for the FCLM and ASRT projects combined, the amount released to date has been $37.5M and the life-to-date spent by December 2012 is forecast to be $32.8M.

Part B: Preferred Alternative

Description of Preferred Alternative: Continue Fuel Channel Life Management Project

OBJECTIVES

Upon completion of the project, OPG will have the plans, tools, and methodologies to acquire and analyze inspection and surveillance data to determine if fuel channels are fit for service to the targeted service lives of 247,000 EFPH at Pickering and 210,000 EFPH at Darlington. This is in support of Pickering Continued Operations and Darlington Refurbishment.

PROJECT EXECUTION STRATEGY

The FCLM project was planned to be executed in three stages: Phase 1 (funded by Partial 1 BCS) to define R&D scope and to engage CNSC; Phase 2 (funded by Partial 2 & 3 BCS) to execute R&D and meet CNSC requirements to confirm fuel channel fitness-for-service; Phase 3 (funded by this BCS) to integrate R&D to support license renewals. Phases 1 and 2 will be completed by end of December 2012, while Phase 3 has been expanded to include the discovery R&D issues from Phase 2.

The discovery issues related to pressure tube fracture toughness and annulus spacer embrittlement will involve additional testing and modelling as follows:

- In the area of pressure tube fracture toughness, additional testing and data modeling is required to validate the proposed new fracture toughness model for higher hydrogen contents, and to refine the understanding at the lower temperature regime for practical heat-up and cool down procedures.
- In the area of annulus spacers, the rate of degradation caused by newly discovered degradation mechanisms (i.e. transmutation of nickel into helium, causing helium voids) must be established. This information is required to enable continued demonstration of fuel channel fitness-for-service until the Darlington units are ready for refurbishment.

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PROJECT DELIVERABLES FUNDED BY THIS BCS

FRACTURE TOUGHNESS

- Additional burst tests and small specimen tests to better understand the fracture toughness of pressure tubes in the transition temperature region. The results of these tests may influence the pressure/temperature operating envelope, particularly during reactor heat up and cool down, in all units.
- Pressure tube burst tests at greater than projected end-of-life hydrogen concentrations using an alternative method of hydriding – this work is to support demonstrating additional fracture toughness margin at end-of-life.
- Third party review and validation of new pressure tube fracture toughness model proposed in 2012, and revision of model (if required).

CRACK INITIATION

- Complete technical basis reports to support crack initiation models (overload, fatigue and delayed hydride cracking).
- Complete third party reviews of upgraded methodologies for crack initiation assessments.

SPACERS

- Development of predictive capabilities to project spacer conditions, given degradation mechanisms.
- Development of fitness-for-service guidelines to assess retrieved spacer results.
- Testing of the spacers from the D1321 SFCR, and assessments based on pre-determined acceptance criteria for fitness-for-service; project the next monitoring interval based on test results, and re-assess spacer surveillance requirements accordingly.
- Piloting the HFIR Program, including material procurement, reactor setup and the retrieval, shipping and testing of the first sample.

PROBABILISTIC CORE ASSESSMENT / LEAK-BEFORE-BREAK

- Development of a probabilistic leak-before-break and fracture protection methodologies, as the existing deterministic methods have many embedded conservatisms according to industry experts
- Integrate new crack initiation methodologies into the Probabilistic Core Assessment process.

INTERFACE AND COMMUNICATION WITH CNSC

- Continue communication with CNSC to expedite acceptance of new models and methodologies by the CNSC.

PROJECT COMPLETION

Project is targeted for completion and close-out by June 2015. A PIR is to be completed by June 2016.

Deliverables:	Associated Milestones (if any):	Target Date:
Completion of a third party review of the new pressure tube fracture toughness model proposed in 2012.		December 31, 2013
Completion of the technical basis report(s) to support the new crack initiation models (overload, fatigue and delayed hydride cracking).		December 31, 2013
Completion of four additional pressure tube burst tests to validate the new pressure tube fracture toughness model.		December 31, 2014
Initiation of accelerated material irradiation program using the HFIR test reactor at ORNL.		December 31, 2014

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Completion of one pressure tube burst test at greater than projected end-of-life hydrogen concentration (i.e. 120 ppm or higher) using an alternative hydriding method.		December 31, 2014
Completion of development of a probabilistic pressure tube leak-before-break methodology for review by CSA Technical Committee.		December 31, 2014
Project Close Out		June 30, 2015

Part C: Other Alternatives

Base Case: Status Quo – No Further Project Funding

NOT RECOMMENDED:

In the case of Pickering Continued Operations, the assumption of operation to 247,000 EFPH is dependent on demonstration of adequate pressure tube fracture toughness and resultant demonstration of leak-before-break. The most recent R&D findings indicate that fracture toughness of pressure tubes depends heavily on hydrogen concentration, which increases as the reactor ages. A preliminary fracture toughness curve for higher hydrogen content was proposed in 2011 and analysis has shown that the current operating envelopes for both Pickering and Darlington units do not demonstrate protection against fracture during warm-up and cool-down.

Pickering stations may be able to accommodate this new curve by adjusting their pressure/temperature operating envelope. However, an analysis conducted in December 2011 indicated that Pickering units will not be able to demonstrate leak-before-break in 2013 under a conservative deterministic assessment. The alternative approach of demonstrating leak-before-break probabilistically using more realistic distributions of data was originally intended to be 2013-2015 project work scope. Therefore, should this project not continue, probabilistic leak-before-break methodology development would still need to be completed to satisfy Pickering's license condition, and would have to be funded from base OM&A.

In the case of Darlington, it was originally projected that Darlington could operate to 187,000 EFPH with high confidence. From a fracture toughness perspective, the situation is similar to Pickering described above, but more severe. It is likely that the station will not be able to change their pressure/temperature operating envelope on warm-up and cool-down to accommodate the new fracture protection curve. The original 2013-2015 project scope included probabilistic fracture protection and leak-before-break development to help remove the over-conservatisms built into a deterministic assessment. Without the timely development of a probabilistic leak-before-break methodology, Darlington may only be able to rely on a probabilistic core assessment to demonstrate to the regulator that the probability of a pressure tube rupture is acceptably low. Otherwise, Darlington may need to be shutdown due to the violation of the associated license condition.

In addition, a significant portion of the work planned for 2013-2015 in the FCLM project is attributed to discovery work associated with spacer degradation. Without the planned work, OPG will not be able to demonstrate to the regulator that PT/CT gap can be maintained to the interim target (set by the CNSC) of 2014, and thus will detrimentally affect the license renewal of Darlington. In turn, this will lead to significant impact to the Darlington Refurbishment schedule, or lead to significant economic loss due to unit lay-up during the preparation for Darlington Refurbishment.

Alternative 2: NOT RECOMMENDED - Do Less or Delay Project

The scope proposed has been thoroughly reviewed to ensure that it contains only items that are essential to allowing Pickering and Darlington units to reach their targeted operating lives of 247,000 EFPH and 210,000 EFPH, respectively. Doing less than the proposed scope in Alternative 1 may result in the advancement of the Darlington Refurbishment schedule or lay-up of the reactor units. It is also CNSC's expectation that the scope under Alternative 1 is completed within the proposed time to support station license renewals.

Alternative 3: NOT RECOMMENDED - Request Regulatory Relief on Life Limiting Isssues

Even though the research and development work conducted thus far has allowed OPG to gain additional understanding on the magnitude, mechanism and rate of the fuel channel component degradation, two major discovery issues, namely, fracture toughness at high hydrogen concentration and spacer integrity and mobility due to helium production are yet to be investigated. It is prudent for OPG to ensure the fuel channel components are fit for service to their targeted operating lives as a nuclear safety-conscious organization. Also, as a responsible organization, OPG has been communicating the R&D findings to the regulator. Therefore, it is unlikely that regulatory relief will be granted.

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary

Part D1: Project Cash Flows (FCLM Project – OM&A)									
Part D: Project Cash Flows									
k$	**LTD**	**2011**	**2012**	**2013**	**2014**	**2015**	**20--**	**Future**	**Total**
Currently Released	8,172	10,058	13,402						31,632
Requested Now	-			15,687	6,274	459			22,420
Future Required	-								
Total Project Cost	8,172	10,058	13,402	15,687	6,274	459			54,052
Ongoing Costs	-								
Grand Total	8,172	10,058	13,402	15,687	6,274	459			54,052

Estimate Class:	Class 2	**Estimate at Completion:**	54,052(OM&A)	**OAR Approval Amount:**	55,236

Additional Information on Project Cash Flows (optional):

The "Currently Released" figures in 2011 and 2012 reflect the summation of the originally released amount and the adjustments due to approved budget underspending and unused contingency. The 2011 originally released amount and adjustment are $12,830k and $(2,772)k, respectively. The 2012 originally released amount and adjustment are $13,403k and $(1)k, respectively. The Total "Currently Released" column reflects these adjustments as well.

Part D2: Project Cash Flows (ASRT Project – Capital):									
k$	**LTD**	**2011**	**2012**	**2013**	**2014**	**2015**	**20--**	**Future**	**Total**
Currently Released		512	672						1,184
Requested Now				0					0
Future Required									
Total Project Cost		512	672						1,184
Ongoing Costs									
Grand Total		512	672						1,184

Estimate Class:	Class 1	**Estimate at Completion:**	1,184 (Capital)	**OAR Approval Amount:**	55,236

Additional Information on Project Cash Flows (optional):

The "Currently Released" figures in 2011 and 2012 reflect the summation of the originally released amounts and the adjustments due to approved budget underspending and unused contingency. The 2011 originally released amount and adjustment are $939k and $(427)k, respectively. The 2012 originally released amount and adjustment are $2,145k and $(1,473)k, respectively. The Total "Currently Released" column reflects these adjustments as well.

The ASRT (capital) project will be closed in Dec 2012. No additional funding is required.

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case	Do Less	Alternative 3	Alternative 4
Project Cost	22,420	0	N/A	N/A	
NPV (after tax)	1,500,000	N/A	N/A	N/A	

Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):

1. Project Costs shown above are the incremental going forward costs.
2. The NPV value is in 2012$.
3. The Darlington Refurbishment Project Unit Outage Schedule is the same in the Base Case and the Preferred Alternative. The unit outages are assumed to be 36 months long with 16/19 month overlaps. The first unit outage is scheduled for Oct 2016.
4. Station operating costs are the same in the Base Case and the Preferred Alternative except for fuel and fuel-related costs which are not incurred when the units are not operating.
5. End-of-Life Assumptions for the Base Case and the Preferred Alternative are summarized in the following table:

Case	Pickering	Darlington
Original High Confidence End-of-Life Projection (before FCLMP)	210,000 EFPH	187,000 EFPH
Base Case (Stop project in Dec 2012)	247,000 EFPH[1]	End of 2014 for all units[1,2,3]
Preferred Alternative (Additional $22.4M release for 2013-2015)	247,000 EFPH	210,000 EFPH

[1]Provided that Probabilistic LBB methodology development is funded by Base OM&A to meet regulatory commitments in 2013

[2]Based on correspondence from CNSC, OPG would need to perform additional work (as documented in the Long Term Spacer Management Plan) in order to prove spacer integrity beyond the end of 2014

[3]A sensitivity case was run assuming that in the Base Case, Darlington units obtained 187,000 EFPH. As part of this case, probabilistic LBB methodology is assumed to be funded outside of this project and completed by 2013, and it is assumed that work on spacer integrity (funded outside of this project) is sufficient to prove spacer integrity beyond 2014.

Economic Analysis

Alternatives 2 and 3 were not analyzed economically as they are not considered to be feasible in achieving the desired objectives. The economic analysis performed for this release does not attribute any value to potential additional life from the Pickering units as the current view is that work done to date has already yielded high confidence in the Pickering units achieving 247 kEFPH, with the proviso than there is follow-up work needed to "prove", or further validate, this high confidence assessment, some of which is dependent on the work scope in this BCS being completed on schedule. However, since this follow-up work would need to be completed in any event to confirm the high confidence assessment for the Darlington fuel channels, there are no costs or specific work scope in this release which is solely associated with confirming the high confidence in the Pickering fuel channel life assessment.

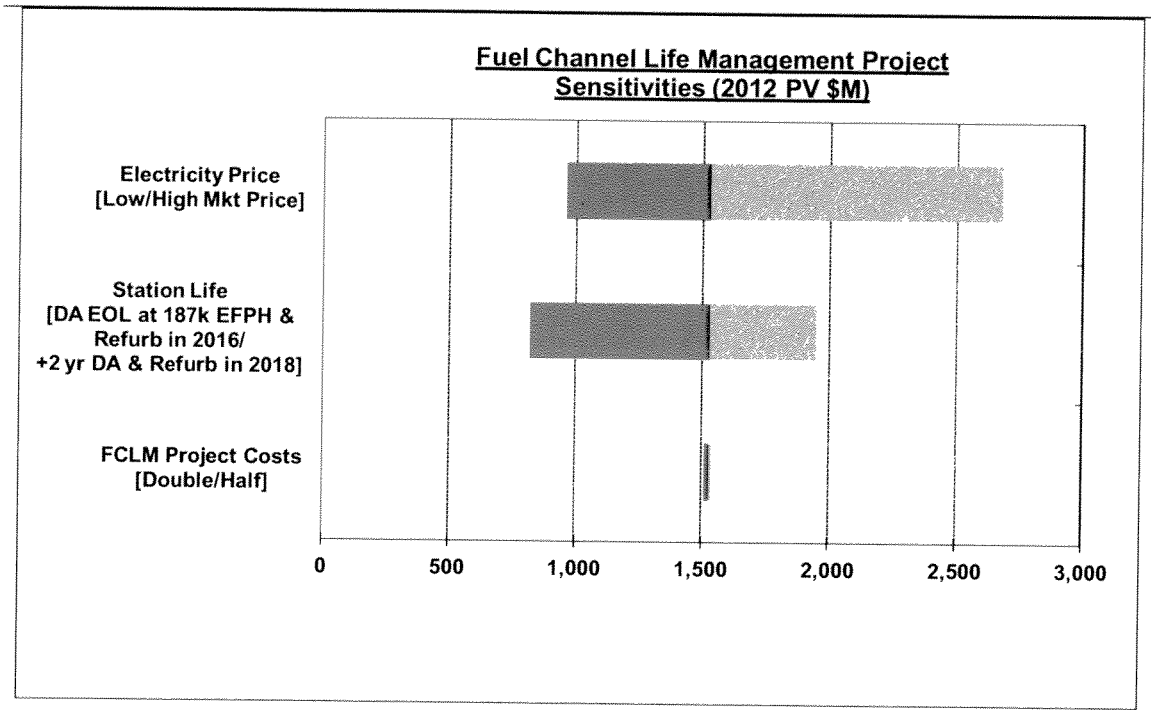
The value to the provincial electricity customers of Alternative 1 compared to the Base Case is estimated at $1.5 Billion. The following tornado diagram shows the key sensitivities of the results.

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary



Results of the economic assessment were tested for sensitivity to key inputs such as assumed electricity price, length of additional station life achieved, and project costs, and indicate the following:

(i) Assumed Electricity Price: The value is extremely sensitive to the assumed electricity price. In a high priced regime, the value would be approximately $2.7 B. In a low priced regime, the value would be approximately $0.96 B. A low priced regime could result from low or declining electricity demand growth (which can result, for example, from a prolonged economic slowdown) and low or declining gas prices, and/or high conservation which could result in a prolonged period of significant surplus baseload generation.

(ii) Length of Additional Station Life Achieved: The value is sensitive to the station life that can be achieved with high confidence. If the FCLM project were to result in the Darlington units being able to operate only to the previous high confidence expectation of 187 kEFPH, significant "idle time" would result for these units given that there is a low probability of starting the Darlington refurbishment any earlier than 2016, and the expected value would be approximately $0.8 B. However, if the FCLM project were to result in the Darlington units being able to operate to 225k EFPH and the start of refurbishment was deferred to 2018, then the value could be as high as approximately $1.9 B.

(iii) Project Costs: The value is insensitive to FCLM project costs. Project costs include the incremental costs of the fuel channel life management project. The sensitivity analysis shows that a doubling of these costs has a minimal impact on the expected PV.

Part F: Qualitative Factors

The completion of the scope in the Preferred Alternative of this project is critical to the Continued Operations of Pickering and to the Refurbishment of Darlington. Since OPG operates the first CANDU units to be impacted by the fuel channel degradation mechanisms being investigated, our R&D findings may present financial opportunities when other CANDU units in the world are approaching their end-of-life.

Type 3 Business Case Summary

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	See below			
Scope	See below			
Schedule	See below			
Resources	Delay in project schedule may occur due to unavailability of specialized resources who cannot be easily replaced. Reasons may include labour disputes or commitment to other work programs in the vendor company.	Mitigate - Obtain resource commitment from vendors. Accept risk if resource unavailabiliy is due to labour disputes.	Low	Medium
Quality/ Performance	See below			
Technical	If the Probabilistic Leak-Before-Break methodology cannot be completed or accepted by CNSC within 15 months, then additional time and funding may be required to expedite the completion and acceptance.	Mitigate - Expert resources are currently gathered to form an expedited plan to ensure probabilistic LBB methodology completion and acceptance in 15 months.	Low	Medium
Technical	Unexpected negative results from testing of surveillance material, inspections, or R&D work may result in a reduced projection of available service life for fuel channels at Pickering and/or Darlington.	Mitigate - Set aside contingency on COG Joint Project work. Additional inspection and surveillance work has been identified as contingency scope in the "Long Term Darlington Life Management Plan for Inconel X-750 Spacers". Accept – The results of testing, inspections and R&D are outside the control of the project.	Low	High
Cost	Increase in cost of R&D (by 50%) if current funding partners do not participate in cost-sharing in the COG Joint Projects.	Mitigate - Early alignment with funding partners' senior management; Seek potential partners from other utilities.	Low	High
Cost	Increase in cost due to a vendor switching their cost model for full cost recovery due to changes to its corporate mandate and changes to federal funding. Future quotes from vendor may be higher than anticipated.	Mitigate - Set aside contingency on COG Joint Project Work.	Med	Med
Cost	Increase in cost due to discovery work scope, indeterminate results or unexpected results.	Mitigate - Set aside contingency on COG Joint Project Work.	Med	Med
Cost	Increase in project cost if there are insufficient funds in the COG Fuel Channel R&D program (which is supporting project deliverables).	Mitigate - Early confirmation of COG R&D scope and funding + Set aside contingency on COG Joint Project Work.	Low	Med
Scope	Increase in scope due to discovery issues, indeterminate results or unexpected results.	Mitigate - Set aside contingency on COG Joint Project Work.	Med	Med
Scope	Unexpected scope cuts from the D1321 outage will cause the project to have insufficient information to perform assessments on fuel channel fitness-for-service.	Mitigate - Communicate to the outage planning organization that work is essential to the continued operation of the stations.	Low	Med

Type 3 Business Case Summary

Scope	CNSC may request additional work to be performed in support of OPG's request for license renewal.	Transfer - If there are additional CNSC requests that the project cannot complete by the targeted project end date, then the responsibility of completing these requests will be transferred to the base engineering organization.	Med	Med
Schedule	Delay in project schedule may occur due to discovery work scope, indeterminate results or unexpected results.	Mitigate - Obtain resource commitments from vendors to support project in case of schedule delays; Set aside contingency for scope expedition.	Med	Med
Schedule	Delay in project schedule may occur due to equipment malfunction.	Mitigate - Ensure commissioning program of equipment is conducted; Set aside contingency on COG Joint Project Work.	Low	Med
Schedule	Outage delays caused by other work programs will delay the retrieval of the D1321 SFCR spacer, thereby impacting the planned testing schedule at the vendor facility.	Accept - outage delays caused by other work programs are beyond the control of the project.	Low	Med
Quality	Information on spacer integrity is heavily reliant on the retrieval of the D1321 SFCR spacer. If the condition of the spacer upon retrieval and post-shipping is unsatisfactory, then the quality of the spacer data obtained may not allow the project to make conclusive assessments of spacer material conditions.	Mitigate - An improved process of spacer retrieval and shipping has been designed by Inspection and Maintenance Services.	Low	Med
Quality	Should the Annulus Spacer Retrieval Tool (ASRT) not perform as per its design, then the spacer retrieval in D1321 may not be successful, potentially not allowing the project to make conclusive assessment of spacer material conditions.	Mitigate - Mock up of the tool and process will be conducted prior to the outage.	Low	Med
Quality	If the Helium modelling work conducted at Oak Ridge National Laboratory cannot provide predictive capability of spacer material degradation, then the confidence in spacer material conditions may be uncertain.	Transfer - Insufficient prediction capability will need to be made up by additional spacer material surveillance, and will be the responsibility of the base engineering organization as the project would have ended by the next available outage.	Med	Low

Additional Risk Analysis:

Long term business risk to demonstrate fuel channel fitness-for-service (post project):
Management of fuel channel fitness-for-service must continue even after the completion of this project. As units age, the CNSC is expecting that there is sufficient inspection and surveillance data to support the projections that the units are safe to operate to the end of their targeted service lives. An expansion of fuel channel inspection scope has been proposed to the outage organization with the potential for outage extension. The "Long Term Darlington Life Management Plan for Inconel X-750 Annulus Spacers" has also been submitted to the CNSC, stating OPG's plan to retrieve and test intact spacers from Single Fuel Channel Replacement campaigns in outages, as well as during Darlington's Refurbishment.

Type 3 Business Case Summary

Part H: Post Implementation Review (PIR) Plan				
Type of PIR	**Target Project In Service Date**		**Target PIR Completion Date**	
Simplified	2015-06-30		2016-06-30	
Measurable Parameter	**Current Baseline**	**Target Result**	**How will it be measured?**	**Who will measure it? (person/group)**
New fracture toughness curves reflecting effect of hydrogen concentration are available	Lower bound curve in CSA N285.8 – based on 30 ppm nominal hydrogen concentration	Updated fracture toughness curves reflecting effects of hydrogen concentration, covering lower-shelf, upper-shelf and transition temperature regime	Acceptance of new fracture toughness curves by the CNSC.	Major Components Engineering Department
New flaw assessment methodology for flaw initiated by overload, fatigue and DHC available	Conservatisms in current methodology has resulted in several flaws in Pickering B not meeting crack initiation criteria – imposing limits on number of heat up / cool down cycles on operation and re-inspection frequencies	Updated flaw assessment methodology that increases the acceptable flaw size envelope, demonstrating that PTs have a higher resistance to crack initiation that currently given credit for.	Acceptance of updated flaw assessment methodology by the CNSC.	Major Components Engineering Department
Approach available to assess and project spacer degradation (mobility and integrity)	Spacers are currently not on a routine surveillance program for degradation.	Long term spacer plan issued to address surveillance of spacers to end-of-life.	Acceptance of Darlington long term spacer plan by the CNSC	Major Components Engineering Department
Probabilistic core assessment (PCA) available for flaws and PT/CT contact updated from latest R&D findings.	PCA for flaws and contact currently do not reflect latest R&D findings	Updated PCA for flaws and PT/CT contact	Acceptance of updated PCA for flaws and PT/CT contact by CNSC.	Major Components Engineering Department
New probabilistic leak-before-break methodology developed for use.	Deterministic leak-before-break assessment with many embedded conservatisms	New probabilistic leak-before-break methodology developed incorporating latest knowledge in PT fracture toughness	Acceptance of new probabilistic leak-before-break methodology by CNSC.	Major Components Engineering Department

Type 3 Business Case Summary

Part I: Definitions and Acronyms
AACE – Advancement of Cost Engineering International
ASRT – Annulus Spacer Retrieval Tool
COG – CANDU Owners Group
CNSC – Canadian Nuclear Safety Commission
CT – Calandria Tube
EFPH – Equivalent Full Power Hours
FCLM – Fuel Channel Life Management
HFIR – High Flux Isotope Reactor
LBB – Leak-Before-Break
LCMP – Life Cycle Management Plan
MCED – Major Components Engineering Division
ORNL – Oak Ridge National Laboratory
PCA – Probabilistic Core Assessment
PT – Pressure Tube
SFCR – Single Fuel Channel Replacement

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For Internal Project Cost Control

Type 3 Business Case Summary

Appendix A: Summary of Estimate										
Project Number:	10-62444 & 28-66567	**Facility:**	Nuclear							
Project Title:	Fuel Channel Life Management Project and Annulus Spacer Retrieval Tool Project									
	Estimated Cost in k$									
	LTD	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Future**	**Total**	**%**
10-62444 FCLMP (OM&A)										
OPG Project Management	1,098	1,141	1,259	1,208	430	147			5,283	11
OPG Engineering	247	235	256	493	179	65			1475	3
Permanent Materials										
Design and Construction										
Consultants										
Other Contracts/Costs	6,827	8,682	11,887	10,849	4,410	155			42,810	86
Interest										
Subtotal without Contingency	**8,172**	**10,058**	**13,402**	**12,550**	**5,019**	**367**			**49,568**	**100**
FCLM Contingency				3,137	1,255	92			4,484	
FCLM Subtotal	**8,172**	**10,058**	**13,402**	**15,687**	**6,274**	**459**			**54,052**	
Removal Costs Included										
28-66567 ASRT (Capital)										
OPG Project Management		125	126						251	21
OPG Engineering		46	86						132	11
Permanent Materials		336	582						917	78
Design and Construction			174						174	15
Other Contracts/Costs			-335	(See Comments on Page A-5)					-335	-28
Interest		5	39						44	4
Subtotal without Contingency		**512**	**672**						**1,184**	**100**
ASRT Contingency		0	0						0	
ASRT Total		**512**	**672**						**1,184**	
Grand Total (FCLM +ASRT)		10,570	14,074	15,687	6,274	459			55,236	

Type 3 Business Case Summary

Notes			
Project Start Date	2009-08-10	**Project Completion or In-Service Date**	2012-10-15 (ASRT ISD) 2015-06-30 (FCLM Project Completion)
Interest Rate	5.00%	**Escalation Rate**	See Financial Note 2 in Appendix C for %
Definition Cost Included	$0 k	**Estimate at Completion**	$55,236 k

Prepared by:	Approved by:
Nick Berube 2012-09-18 Nick Berube YYYY-MM-DD Assistant Technical Engineer/Officer, FCLMP	Thomas Lau 2012-09-18 Thomas Lau YYYY-MM-DD Project Manager, FCLMP
Rob Harness 2012-09-21 Rob Harness YYYY-MM-DD Project Manager, ASRTP, IMS	John Stopar 2012-09-21 John Stopar YYYY-MM-DD Manager, Field Operations, IMS

Type 3 Business Case Summary

Appendix B: Comparison of Total Project Estimates

Phase	Release	Date (YYYY-MM-DD)	Total Project Estimate in k$ (by year including contingency)						Later	Total Project Estimate
			2009	2010	2011	2012	2013	2014		
10-62444 FCLMP (OM&A)										
Definition	Partial 1	2009-08-10	2,533	9,728	7,741	4,010	908			24,920
Execution	Partial 2	2010-08-09	2,489	6,502	8,978	6,841	2,188			26,998
Execution	Partial 3	2011-08-18	2,489	5,683	12,830	13,403	3,332	1,861	332	39,930
Execution & Closeout	Full	Current	2,489	5,683	10,059	13,402	15,687	6,274	459	54,052
28-66567 ASRT (Capital)										
Definition	Partial 2	2010-08-09			867	2,217	82			3,166
Execution	Partial 3	2011-08-18			939	2,145	82			3,166
Execution & Closeout	Full	Current			512	672	(no additional funding requested)			1,184

Type 3 Business Case Summary

Project Variance Analysis					
Estimated Cost in k$					
k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
10-62444 FCLMP (OM&A)					
OPG Project Management	3,498	8,101	5,283	(1,343)	The Fuel Channel Life Management Project team, who manages the project, as well as prepare technical submissions to the CNSC, will be reduced in staff levels (further than originally anticipated) as the COG R&D program comes to a close. The negative variance indicates this reduction of staff levels in 2014 and 2015.
OPG Engineering	738		1,475		
Other Contracts	27,396	28,874	42,810	13,936	The variance is largely due to additional R&D required to address discovery issues regarding fracture toughness and spacers. The remaining cost increase can be attributed to the business need to evaluate the feasibility of providing additional flexibility to target service lives, and also to the additional third party reviews required to enhance regulator confidence.
Subtotal	**31,632**	**36,975**	**49,568**	**12,593**	
Contingency	0	2,955	4,484	1,529	Since the discovery issues regarding fracture toughness and spacers require additional R&D, where contracts are not yet procured, a 25% contingency is estimated for 2013-2015.
Total	**31,632**	**39,930**	**54,052**	**14,122**	
Removal Costs Included					

Type 3 Business Case Summary

28-66567 ASRT (Capital)					
k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management	212	222	251	29	Costs were under estimated for project management.
OPG Engineering	93	116	132	16	Costs were under estimated for engineering
Permanent Materials	574	725	918	193	Additional funds were required for spare parts and mock up components.
Design & Construction	85	149	174	25	Costs were under estimated for commissioning and construction of mock up.
Consultants					
Other Contracts/Costs	(335)		(335)	(335)	Re-imbursement of shared engineering costs with non-OPG site to share technology.
Interest	23	54	44	(10)	
Subtotal	**652**	**1,266**	**1,184**	**(82)**	
Contingency		1900	0	(1,900)	Contingency to develop automated tooling (alternative concept) was not required.
Total	**652**	**3,166**	**1,184**	**(1,982)**	
Removal Costs Included					

Type 3 Business Case Summary

Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

Project Cost:

(1) Incremental Project Costs are $22,420k for the Preferred Alternative.
(2)
(3)

Financial:

(1) Discount rate is 7% for regulated assets.
(2) Majority of budget is classified under "other contracts", which are escalated at standard labour and materials escalation rates.
(3)

Project Life:

(1)
(2)
(3)

Energy Production:

(1)
(2)
(3)

Operating Cost:

(1)
(2)
(3)

Other:

(1)
(2)
(3)

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

See Part E of the BCS for more information.

Appendix D: References

ONTARIO POWER GENERATION

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Business Case Summary

Pickering A Divider Plate Locking Tab Replacement 13 - 49248 (OM&A)
Partial Release Business Case Summary NA44 - BCS - 33115 - 00003 - R000

Name / Title / Phone	Location	Action	Signature	Date
Nahil Rahman Director - Pickering Projects 701-4053	P72-1	Review BCS		07 Oct 2011
Carl Daniel Director Station Engineering - Pickering 701-5064	P42-3	Review BCS		13 Oct 2011
Jamie Lawrie Director - Nuclear Investment Management 702-5086	P82-3	Review BCS		13 Oct 2011
Glenn Jager Senior Vice President - Pickering 701-3260	P42-3	Submit BCS		16 OCT 2011
Randy Leavitt Vice President - Nuclear Finance 702-5177	P82-3	Review BCS		Oct 21, 2011
Don Power Vice President - Corporate Investment & Asset Planning 400-7172	TCH-07-G05	Review BCS		Nov 18/11
Wayne Robbins Chief Nuclear Officer 702-5294	P82-6	Concur with BCS		Oct 24 2011
Donn Hanbidge Senior Vice President & Chief Financial Officer 400-2395	TCH-19-F27	Approve BCS		NOV 25/11
Tom Mitchell President & Chief Executive Officer 400-2121	TCH-19-A24	Approve BCS		1 Dec 11
Carolyn Sicard Nuclear Investment Management 702-4082	P82-3B6.2	Return for Distribution		

Pickering A Divider Plate Locking Tab Replacement 13 - 49248 (OM&A)
Partial Release Business Case Summary NA44 - BCS - 33115 - 00003 - R000

1/ RECOMMENDATION:

We recommend a **Partial** Release of an **additional $13.14** Million **OM&A** to fund **execution for one unit** for this project. Approval of this request will bring the total to date funding to **$14.38** Million including a contingency of [redacted] The total project is estimated to cost **$ 23.86** Million with an estimated completion date of 2018.

The Business Objective of this **Sustaining** project is to:

- Avoid significant forced outage(s) due to a locking tab failure on the cold leg of the Heat Transport System in Unit 1 and Unit 4
- Ensure that the new divider plate locking tab design will meet or exceed Pickering A Steam Generators (SG's) life expectancy requirements.

If a cold leg locking tab was to fail, it is speculated that it would cause significant damage to the Heat Transport System. A Fitness for Service evaluation has indicated that the Unit 1 cold leg locking tabs made of stainless steel have a lifespan of 6.3 Effective Full Power Years (EFPYs). The Unit 4 bendable style locking tabs have a lifespan of 10.6 EFPYs because they are made of Inconel 625 rather than stainless steel. Based on their current EFPYs, Unit 1 locking tabs require replacement by January 2015 and Unit 4 locking tabs require replacement by November 2018 to prevent locking tab failure. This modification will involve the replacement of the existing bonnet style locking channels on the hot leg side and the bonnet tabs on the cold leg side of the divider plate sealing skin assembly with new channels and bendable locking tabs. The new channels and locking tabs are an improved design and do not require welding. Due to the extended life of the Unit 4 locking tabs they do not require replacement until the P1741 outage. Before we transition to the execution phase of Unit 4 for this project, we will review and challenge the fitness for service of the Unit 4 locking tabs.

A Partial Release is being requested to complete the development of extension tooling, training, execution and closeout activities for the Unit 1 locking tab replacement outage scheduled for the fall of 2012 (P1211).

$000's (incl contingency)	Type	LTD Dec 2010	2011	2012	2013	2014	2015	2016	Later	Total
Currently Released	Develop	1,235								1,235
Adj to Current Release	Adjustments	(381)	381							-
Requested Now	Partial		-	12,847	297					**13,144**
Future Funding Req'd	Full								9,482	**9,482**
Total Project Costs		**854**	**381**	**12,847**	**297**	-	-	-	**9,482**	**23,861**
Non Project Costs										-
Grand Total		854	381	12,847	297	-	-	-	9,482	23,861
Investment Type Sustaining		**Class** OM&A		**NPV** 164 M			**IRR** 123.7%		**Discounted Payback** 4.09	

Submitted By: (Date)

16 OCT 2011

Glenn Jager
Senior Vice President - Pickering

Financial Approval By: (Date)

Nov 25/11

Donn Hanbidge
Senior Vice President & Chief Financial Officer

(OAR Element 1.1 Project in Budget)
Line Approval By: (Date)

1 December 2011

Tom Mitchell
President & Chief Executive Officer

2/ BACKGROUND & ISSUES:

2.1 Adverse Condition:

The Steam Generator Divider Plate sealing skin modification was performed on Units 1, 4, 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purpose of this modification was to address Divider Plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) which was forcing several units to run derated. The steam generator inspections conducted in Unit 5 during the 2005 Spring Outage were the first to be done following installation of the sealing skin/locking tab modification. These inspections revealed that numerous pieces of locking tabs and divider plate sealing skin had broken off in the hot leg (inlet) side of the steam generators (refer to SCR P-2005-03243) due to high cycle fatigue cracking. Further inspections revealed that all 10 affected steam generators experienced locking tab failures, and 4 of 10 steam generators experienced divider plate skin failures. The root causes of this event were deemed to be insufficient design process for the new locking tabs and inadequate installation of the sealing skins to ensure a proper seal. Subsequent steam generator inspections in Units 6 and 8 uncovered more broken locking tabs and sealing skins. No locking tab failures were observed in any of the cold leg heads.

Based on their current EFPYs, Unit 1 cold leg locking tabs require replacement by January 2015 and Unit 4 cold leg locking tabs require replacement by November 2018 to prevent locking tab failure. The replacement strategy for Pickering A will focus on locking tab replacement (currently installed sealing skins will be retained) and minimizing cost, schedule and dose.

2.2 Lessons Learned:

Locking tab replacement is also being performed on Pickering Unit 7 and Unit 8 under a separate project. Locking tabs have been replaced on 6 SGs in Unit 7 and 8 SGs in Unit 8 during the 2008 and 2010 outages, respectively. Welded keepers were installed on the completed SGs in Unit 7 and 8. A Lessons learned report and analysis were completed to determine the root cause of increased cost, schedule and dose incurred during the execution. The analysis concluded that the design of the locking devices had to be modified to not include welding as this caused rework and increased dose and cost. The Pickering B locking tab device has been redesigned to avoid welding. The new Pickering A design will be a bendable style locking tab similar to the Pickering B design. The Pickering B lessons learned report and root cause analysis have been reviewed for this business case summary.

2.3 Current status:

- Preliminary Design was completed in August 2010.
- Detailed Design was completed in September 2011, however, further enhancements will be performed to utilize the lessons learned in tab and tool development from the Pickering B campaigns.
- Prototype tooling development is in progress.
- RFP for execution has been issued.

3/ ALTERNATIVES & ECONOMIC ANALYSIS:

$ Millions	Base Case	Alt 1 (Recommended) Full Cost	Alt 1 (Recommended) Incremental Cost	Alt 2	Alt 3	Alt 4	Alt 5
Revenue	2,677	3,206	3,206				
Base OM&A	(3,728)	(3,989)	(3,989)				
Outage OM&A	(105)	0	0				
Project OM&A	0	(24)	(23)				
Total OM&A	(3,833)	(4,013)	(4,012)	0	0	0	0
Provision							
Capital							
Present Value (PV)	(691)	(528)	(527)				
Net Present Value (NPV)	N/A	163	164				
Internal Rate of Return (IRR) %	N/A	103.2	123.7				
Discounted Payback (Yrs)	N/A	4.1	4.1				

Base Case: × *Not Recommended* - **Stop the project**

This option is not recommended. Based on the Fitness for Service evaluation, the Unit 1 cold leg locking tabs have a life span of 6.3 EFPYs and the Unit 4 locking tabs have a life span of 10.6 EFPYs. The expiry dates for Unit 1 and Unit 4 are January 2015 and November 2018, respectively. If a cold leg locking tab were to fail, there is a potential that locking tab broken bonnets could be carried from the boilers to the pressure tubes where they could reduce or block the cooling flow in some areas of the fuel, potentially leading to overheating of the fuel and resulting in fuel bundle damage.

Alternative 1: ✓ *Recommended* - **Replace Locking Tabs with New Design**

Replace all fasteners and install new channels and bendable locking tabs at all SGs in Unit 1 and Unit 4. This modification will include replacement of the existing bonnet style locking channels on the hot leg side and the bonnet tabs on the cold leg side of the divider plate sealing skin assembly with new channels and bendable locking tabs.

This option is recommended because it will allow for the following (which are aligned with the project objectives):

- SGs to run until End of Life (EOL) without the possibility of locking tab failure
- Ability to remove and/or replace components of the new design with relative ease, if required

Alternative 2: × *Not Recommended* - **Delay the project**

This option is not recommended because the estimated end of life of the cold leg locking tabs on Unit 1 is January 2015. The next Unit 1 outage after 2012 is the fall outage in 2014, which is very close to the end of life for the Unit 1 cold leg tabs. The estimated date of expiry of the cold leg locking tabs on Unit 4 is November 2018 which is before the end of life of the Pickering Nuclear Generating Station (PNGS).

4/ THE PROPOSAL

The following are the objectives and expected results (deliverables) for this Unit 1 Partial Release BCS:

- Project Management
- Detailed Engineering (incorporation of lessons learned)
- Training
- Procurement
- Modification for Unit 1
- AFS

The same objectives will be included in the Full Release for the Unit 4 Divider Plate modification.

5/ QUALITATIVE FACTORS

- SGs to run until End of Life (EOL) without the possibility of locking tab failure
- Ability to remove and/or replace components of the new design with relative ease, if required
- Execution to incorporate lessons learned from Pickering B to ensure installation is less complex, optimizing cost, schedule and dose.

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6/ RISKS ANALYSIS (See Attachment D for details)

Low 1 to 3	Medium 4 to 9	[illegible]

Probability \ Impact	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	[illegible]
1	1	2	3	4	5

Risk Description	Mitigating Activities	Mitigation	Specific Cont'ncy $000's	Probability X Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environmental	Nuclear Safety	Risk Rating (1 to 25)
Extremely high fields due to hot particles in the boilers.	1. Project Design & RP – develop hot particle removal system.	Before		[illegible]	[illegible]	15	5	5	10	5	5	[illegible]
		After		[illegible]	[illegible]	8	1	1	1	1	1	[illegible]
Internal resources may be unavailable to meet the schedule.	1. Design Projects – develop recovery plans for milestones and actions that cannot be met in time. 2. Investigate the possibility of employing additional resources as required.	Before		6	6	6	3	3	3	3	3	9
		After		2	2	2	1	1	1	1	1	2
Radiological conditions may cause delays (ie. contamination and dripping D2O in the boilers)	1. Design Projects – Use extension tooling for removal and installation of fasteners and new locking tabs. 2. Projects is working with RP to develop methods to effectively remove contamination and hot spots such that general radiation fields are lowered. 3. Design Projects/Contractor – Conduct training to ensure personnel have high productivity when working at the primary side of the boilers. 4. Tab Design – Lessons learned from Pickering B locking tab and extension tooling will be used to enhance the Pickering A design.	Before		8	8	4	4	4	8	4	4	8
		After		3	3	2	1	1	1	1	1	3

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Sufficient numbers of experienced and skilled workers may be unavailable to complete the installation. This may lead to schedule delays or inability to complete the installation.	1. Projects will have a more active role in the training and training verification to ensure that acceptable skills are acquired by the trades. 2. Design has been simplified to reduce the reliance on highly skilled trades. 3. Workers will gain experience using extension tooling during U8 divider plate campaign. The use of extension tools will reduce the number of workers required for this modification.	Before		9	9	9	3	3	3	3	3	9
		After		3	3	3	2	2	2	2	2	3
Work may not be executed within the expected dose budget.	Projects/Execution Contractor – Develop methods to improve work productivity therefore reducing execution time and dose.	Before		3	3	3	3	3	6	3	3	6
		After		2	2	2	2	2	4	2	2	4
Potential for cost increase and schedule delay during execution due to interference with other outage work programs or discovery work.	Coordinate outage activities with the Outage SWC. Utilize resource sharing where possible to reduce costs.	Before		3	9	3	3	3	3	3	3	9
		After		1	3	1	1	1	1	1	1	3
Tooling and material costs are higher than estimated	Scope will be limited to only those changes with tangible benefits	Before		9	6	3	3	3	3	3	3	9
		After		6	4	1	1	1	1	1	1	6
Additional costs for unforeseen training requirements and extended training schedule.	A training plan will be developed and closely monitored to ensure efficiency and quality.	Before		9	9	6	3	3	3	3	3	9
		After		3	3	2	1	1	1	1	1	3
P1211 Outage schedule change.	Projects will maintain close communication with the outage manager for schedule changes; the hire on plan will be adjusted accordingly, if required	Before		6	6	4	2	2	2	2	2	6
		After		3	3	2	1	1	1	1	1	3
Potential for safety related events during site execution due to conventional and radiological hazards.	Training will be conducted in representative condition and mockups. RP will be involved in the training to ensure the radiation hazards are being addressed. Boiler room work sequence and durations will be rehearsed during mock up training to ensure that trades are familiar with the actual work requirements and existing hazards.	Before		9	9	6	9	6	9	3	4	9
		After		3	3	2	3	2	3	1	1	3

7/ POST IMPLEMENTATION REVIEW

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date	PIR Responsibility (Sponsor Title)
Simplified	21-Dec-17	17-Dec-18	Manager Component & Equipment – Pickering

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure Person / Group?
1.	Durability of Steam Generator divider plate fastener locking device	Divider Plate locking device failure and broken parts.	Divider plate locking device to remain intact and no broken parts found.	Perform locking tab inspections on Unit 1 during P1411 & P1611 Outages	Components & Equipment Department - Pickering

APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

- AFS: Available for Service
- ALARA: As Low As Reasonably Achievable
- BCS: Business Case Summary
- CNSC: Canadian Nuclear Safety Commission
- D_2O: Heavy Water
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- IRR: Internal Rate of Return
- LOCA: Loss of Coolant Accident
- LTD: Life To Date
- NPV: Net Present Value
- OAR: Organizational Authority Register
- OM&A: Operations, Maintenance & Administration
- OPEX: Operating Experience
- PHT: Primary Heat Transport
- PO: Purchase Order
- PV: Present Value
- PNGS: Pickering Nuclear Generating Station
- PROL: Power Reactor Operating License
- RFP: Request For Purchase
- RIHT: Reactor Inlet Header Temperature
- RP: Radiation Protection
- SCR: Station Condition Record
- SG: Steam Generator

APPENDIX "B" Comparison of Total Project Estimates

$ 000's		This Appendix compares the Total Project Estimate for each BCS										
			Total Project Estimate (by Year incl Contingency)									
BCS Type	Class	Mth	Yr	2007	2008	2009	2010	2011	2012	2013	Later	Total Project Est
Developmental	OM&A	Jun	2007	850	385	520	7,675	7,905	400			17,735
Partial	OM&A	Sep	2011	-	-	-	854	381	12,847	297	9,482	23,861
												0
												0
												0
												0
LTD Spent	OM&A	Aug	2011	87	98	188	481	223				1,077
LTD Spent												0
LTD Spent												0

Comments:

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APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

Financial Assumptions:

Discount Rate:	7%	Cost Escalation (Yr)	3%	SR&D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Depreciation Rate (Capital)	N/A	PST	No	Interest Rate (Capital)	OM&A N/A
Revenue Rate	Nuclear Est	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete:	100%	Fixed Price Contract	No	3rd Party Estimate	No
Quality of Estimate	Budget +30% to -15%	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	Yes	Budgetary Quote	Yes	First Unit Actual Used	No
Firm Vendor Proposal	No	Cost Sharing	No	Competitive Bid	Yes
Reviewed by Sponsor	Yes	Fee for Service	No	Contracts in place	No

Comments:

Rationale for Capital Cost Classification:

N/A

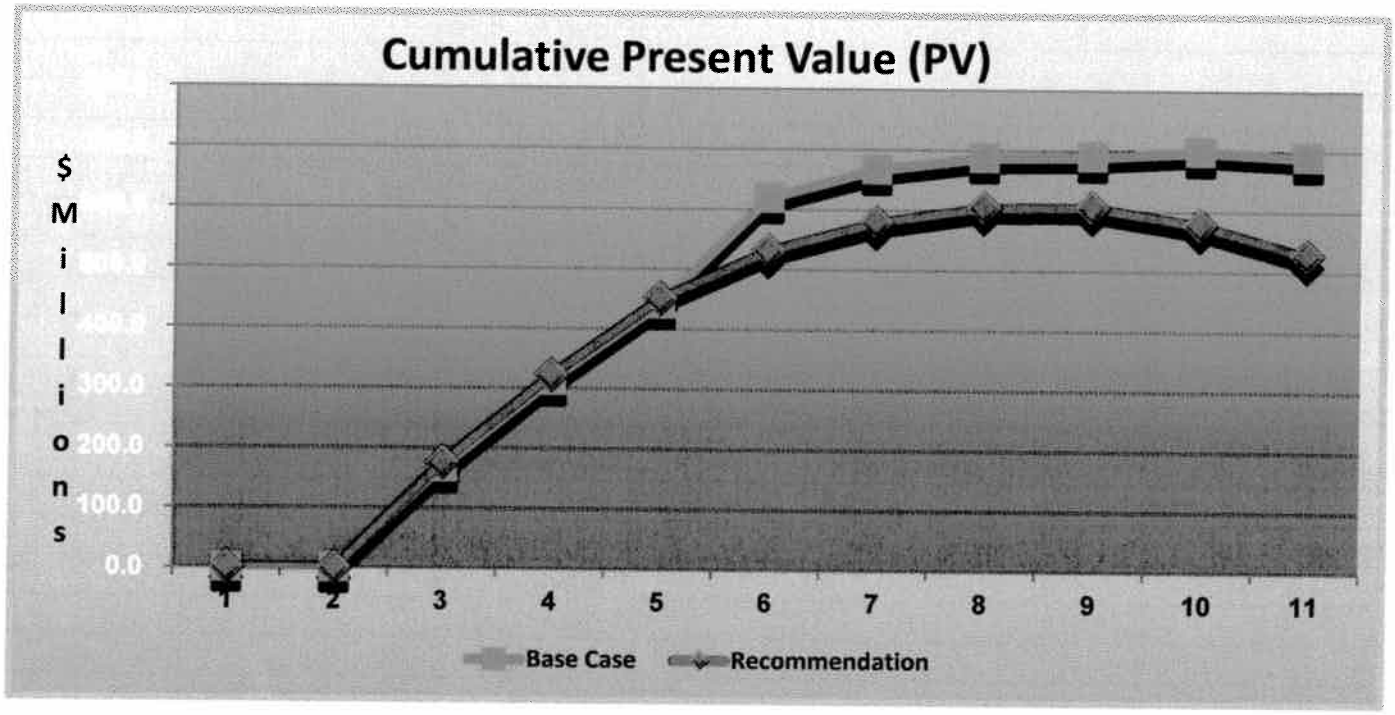
Generation Plan Assumptions:

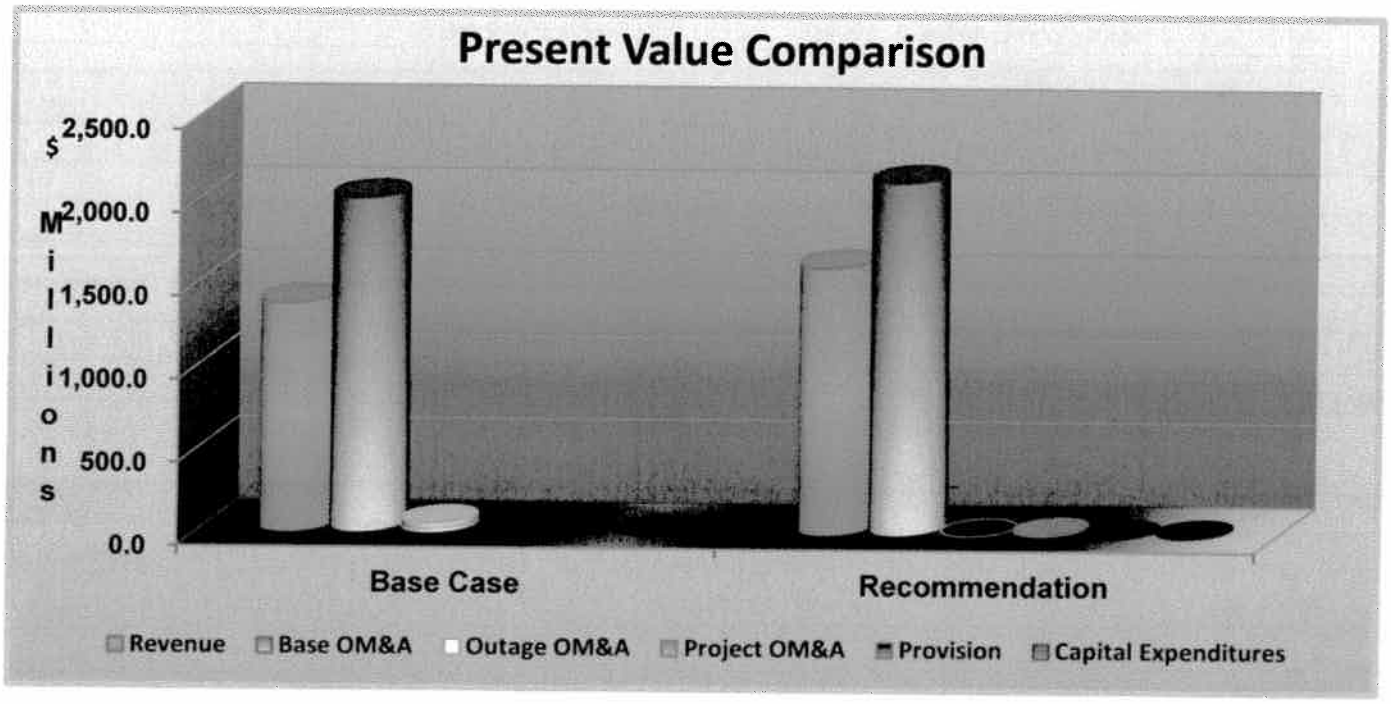
Station	Unit	EOL or Refurb	MW	Planned Outages for Project Work						
Pickering A	1	Jun-20	515	P1211						
	4	Jun-20	515	P1741						
Pickering B	5	Nov-18	516							
	6	Nov-18	516							
	7	Jun-20	516							
	8	Jun-20	516							
Darlington	1	Sep-16	878							
	2	Feb-18	878							
	3	Sep-19	878							
	4	Jan-21	878							

Comments:

APPENDIX "D"

FINANCIAL MODEL – ASSUMPTIONS
Impact on Operations





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APPENDIX "E" *PROJECT DELIVERABLES*

Release Deliverable	Description	Item	Cost ($000's)
Project Mangement	Project Management and Support	Planning and Preparation	511
		Project Execution	180
		Project overhead	139
Detailed Engineering	Design for Unit 1 and Extension Tooling	Design Package for Unit 1	191
		Execution support	60
		Development and production of Tooling	1,525
Training	Training for Tab replacement	Contractor Training	1,439
		Training facility rental	239
		SG Mock up Fabrication	115
		Planning & Preparation	1,115
Procurement	Procurement of materials	Materials for Unit 1	150
Modification	[redacted]		
AFS			
Contingency			
Total			13,144

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Business Case Summary

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ATTACHMENT "A" PROJECT COST SUMMARY

Accounting Basis	$ 000's OM&A	LTD Dec 2010	2011	2012	2013	2014	2015	2016	Later	Total
	Project Mgmnt & Support	530	121	741	77				525	1,994
	Engineering	324	79	1,227	101				700	2,431
	Procurement	[redacted]								
	Construction									
	Other									
										-
										-
										-
	Interest (Capital Project)	[redacted]								
	Project Costs									
	General Contingency									
	Specific Contingency									
	Project Costs	854	381	12,847	297	-	-	-	9,482	23,861

Funding Basis	$ 000's OM&A		LTD Dec 2010	2011	2012	2013	2014	2015	2016	Later	Total
	Current Release	Project Costs	[redacted]								
		Contingency									
		Total									
	Adj to Current Release	Project Costs									
		Contingency									
		Total									
	This Release	Project Costs									
		Contingency									
		Total									
	TTD Released	Project Costs									
		Contingency									
		Total									
	Future Releases	Project Costs									
		Contingency									
		Total									
	Project Funding										
	Contingency Funding										
	Total Funding		854	381	12,847	297	-	-	-	9,482	23,861

Budget	2011 - 2015 Business Plan	854	7,278	7,280	309						15,721
	Variance to Budget	0	(6,897)	3,448	(61)	0	0	0	8,245		4,735
Other	Removal Costs (above)										-
	Inventory W / O										-
	Spare Parts in Invent										-

Reviewed by:	(Date)	Approved by:	(Date)
E.H. Wong Project Manager	Oct 7/2011	Nahil Rahman Director – Pickering Projects	07 OCT 2011

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ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

	$ 000's OM&A	LTD Aug 2011	Total Project Last BCS Jun 2007	Total Project This BCS Aug 2011	Variance	Comments
Scores Basis	Project Mgmnt & Support	575	1,539	1,994	455	See Note 1
	Engineering	373	666	2,431	1,765	See Note 2
	Procurement	[redacted]				
	Construction					
	Other				-	
					-	
					-	
					-	
	Interest (Capital Project Only)					
	Project Costs (Scores Basis)					
	General Contingency					
	Specific Contingency					
	Project Costs (Scores Basis)	**1,077**	**17,735**	**23,861**	**6,126**	
Other	**Removal Costs included above**				-	
	Inventory to be written off				-	
	Spare Parts in Inventory				-	

Comments:

Note 1:

- Increased support required during testing and qualification of extension tooling and new locking tab design.
- Additional costs due to increase in project duration.
- The addition of SAVH and project overhead has been budgeted for in this estimate.

Note 2:

- Increased Design Engineering resources are required for new locking tab design and extension tooling development and qualification.
- The addition of SAVH has been budgeted for in this estimate.

Note 3:

- Additional Trades personnel hours for pre-installation training were not accounted for in the original budget. These hours have been accounted for in this estimate.
- Due to high fields at the boilers and due to longer that originally estimated installation duration, the total dose for the job is higher and additional trades are required to distribute the dose during execution.
- There is no mock up of the Pickering A steam generator and Trades will required several mock-ups for training purposes. The additional cost for the training mock-ups has been included in this estimate.

Note 4:

- Contingency is increased due to the increase in cost and as a result of lessons learned from Pickering B.

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ATTACHMENT "C" SCHEDULE

Key Milestones

Completion Date	Description
23-Dec-11	ICA – Unit 1 Installation Labour Contracts Awarded
12-Oct-12	SOI – Unit 1 Start of Installation
28-Dec-12	AFS – Unit 1 Available for Service
15-Mar-16	FRF - Full Funding Release Approved (to be confirmed based on U4 execution window)

A Project Execution Plan (PEP) will be approved by 27-Oct-11

In Service Declarations: (Capital only)

Date	Description	$000's (Total = Project Cost Incl contg)	% In Service (= 100%)

Comments:

N/A

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Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 100	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 month	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 > $15MCat. 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 ORMajor 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 OrderCat. 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 finesORPotential 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 spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger 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 scheduleORPossibility 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 - reportableAdministrative infractionsPublic 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 qualityRoutine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-complianceORRoutine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker	Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God	

Type 3 Business Case Summary

Final Security Classification of the BCS: **OPG Confidential**

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

Executive Summary and Recommendations				
Project #:	10-80014	**Title:**	Fuel Channel Life Extension Project	
Phase:	Definition and Execution		**Release:**	Partial
Facility:	Nuclear		**Records File:**	N-BCS-31100-10009 R0
Class:	OMA		**Investment Type:**	Value Enhancing

Project Overview

We recommend the release of $41.2 M [redacted] base costs plus [redacted] contingency).

This partial release is to fund Phase 1 of the Fuel Channel Life Extension (FCLE) project during 2014 and 2015. The project covers the period 2014 – 2017 with closeout activities taking place in the first half of 2018. The total project estimate is $105.8M (including [redacted] contingency). Another CANDU operator is expected to share the costs on a portion of the research and development (R&D) requirements of the project scope. Net of this cost sharing, costs to OPG are estimated to be $67.4 M (including [redacted] contingency). The project estimate is considered an AACE Class 4 estimate and includes [redacted] contingency, including a [redacted] annual escalation contingency for the work expected to be conducted by R&D vendor, plus [redacted] specific contingency should non-OPG irradiated pressure tube (PT) material need to be acquired.

There are also consequential costs associated with operating the units longer, should this project be successful (mainly additional Spacer Location and Repositioning (SLAR) campaigns at Pickering and several single fuel channel replacements in which annulus spacers are retrieved). These consequential costs total approximately $147M, including $71M for contingent work which may not be required.

This project is required in order to extend confidence statements on fuel channel (FC) component life past the current 247k Equivalent Full Power Hours [EFPH] to at least 261k EFPH for Pickering and past 210k EFPH to at least 235k EFPH for Darlington. This project supports the OPG and Canadian Nuclear Safety Commission (CNSC) Protocol Agreement "Additional Protocol for Probabilistic Leak Before Break Assessments and X-750 Annulus Spacer Hold Points" [1]. This would enable OPG to achieve the following business objectives:

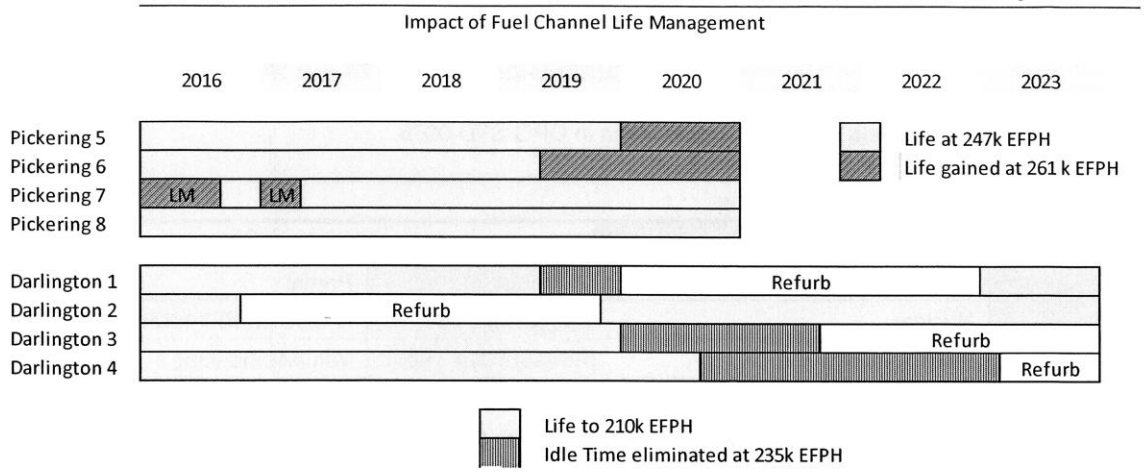
- Operate all Pickering units to the end 2020, without life management outages on any units, which requires high confidence in fitness-for-service of the Pickering fuel channels to 261k EFPH
- Operate the Darlington units to the planned start of refurbishment dates for all units without any idle time or life management outages, given a management decision to remove the overlap of the first two units' refurbishment outages. This would require high confidence in fitness-for-service of the Darlington fuel channels to 235k EFPH, with a confidence level statement available by Q2 2018

To meet these business objectives, and to be able to continue to provide assurance of fitness-for-service for OPG fuel channels, the FCLE project must start in early 2014. Additional business commitments above the base program and beyond this project to achieve/maintain high confidence in operating Darlington to 235k EFPH and Pickering to 261k EFPH are outlined in Part A.

The schematic in Figure 1 shows the additional life which would be enabled by extending high confidence in the Pickering fuel channels fitness-for service from 247k EFPH to 261k EFPH and in the Darlington fuel channels fitness-for-service from 210k EFPH to 235k EFPH. The idle time avoided on the last 3 Darlington units to be refurbished is estimated at 57 months.

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

Figure 1: Impact of Fuel Channel Life Extension on Operating Times for Darlington and Pickering



The value to the electricity system if the FCLE Project is pursued and successfully achieves high confidence in fitness-for-service of the fuel channels to 261k EFPH at Pickering and to 235k EFPH at Darlington is estimated at $1.1 B (PV 2013$). The majority of the value ($0.9 B (PV 2013$)) arises from enabling the elimination of approximately 57 months of idle time on the Darlington units, which would occur if the planned refurbishment schedules is implemented, but fitness-for-service of the fuel channels beyond 210k EFPH were not achieved. The remainder of the value ($0.2 B (PV 2013$)), arises from enabling operation of all Pickering units to the end of 2020. This value is net of the estimated $105.8 M cost ($64 M (PV 2013$)) of implementing the FCLE project, as well as net of the estimated $147 M ($77 M (PV 2013$)) of consequential costs associated with longer operation and increased life cycle management work on both Darlington and Pickering.

This FCLE project continues work done under Project 62444 – Fuel Channel Life Management (FCLM). R&D work and technical assessments conducted under that project enabled the establishment of a high confidence statement in fitness-for-service of the Pickering fuel channels to 247k EFPH. The FCLM project also had, as a target, the establishment of high confidence in fitness-for-service of the Darlington fuel channels to 210k EFPH; however, this objective was not achieved by the end of 2012, primarily because of emergent issues with the integrity of Inconel X-750 annulus spacers in the Darlington fuel channels. On-going work in the FCLM project as well as some funding ($4.5 M) from this FCLE project, primarily for irradiation of Darlington spacers in a high flux R&D reactor, is required to enable assessment of high confidence in 210k EFPH for the Darlington fuel channels by 2015.

Major degradation mechanisms on Fuel Channels to be investigated can be categorized as follows:

- Effect of Hydrogen/Deuterium ingress on pressure tube fracture toughness.
- Pressure tube crack initiation by delayed hydrogen cracking (DHC), fatigue, or overload.
- Mobility and integrity of Inconel X-750 annulus spacers and prevention of pressure tube/calandria tube contact.

The FCLE project is planned to be executed in two stages:

Phase 1 Partial Release (this release):

- Research and Development (R&D) scope definition, inspection and maintenance scope definition
- CNSC concurrence on the Burst Test Matrix and scope of subsequent HFIR Irradiation work.
- Initial R&D execution including Phase 1 of Burst Test matrix and Phase 2 of High Flux Isotope Reactor (HFIR) irradiation work
- Surveillance testing of the PT removed from D1321 SFCR
- Third party reviews of technical submissions to CNSC and supporting project management activities

Phase 2 Full Release (future release planned for 2015):

- Complete remaining R&D including remaining Burst Tests and HFIR determined from the Phase 1 results
- Complete remaining inspection and maintenance scope assessments
- Refinement of models and methodologies based on the R&D results
- Surveillance testing of the PT and spacers from P1561 SFCR
- Third party reviews of technical submissions to CNSC and supporting project management activities

At the completion of the project, it is expected that tools and methodologies will have been established to enable assessment of high confidence in the fitness-for-service of pressure tubes to 235k EFPH for Darlington and to 261k EFPH for Pickering.

Project Cash Flows

M$	LTD	2014	2015	2016	2017	2018	2019	Future	Total
Currently Released									
Requested Now	-	8.5	32.7						41.2
Future Required	-			37.6	26.5	0.6			64.6
Total Project Cost		8.5	32.7	37.6	26.5	0.6			105.8
Ongoing Costs	-		22.0		4.5	63.6	53.5	3.1	146.7
Grand Total		8.5	54.7	37.6	31.0	64.1	53.5	3.1	252.5

Estimate Class:	Class 4	**Estimate at Completion:**	[redacted]
NPV:	$1,100 M	**OAR Approval Amount:**	252.5

Additional Information on Project Cash Flows (optional):

Project Cash Flows, Estimate at Completion, and OAR approval amount show in the table above assumes no co-funding by any other party. The Estimate at Completion does not include contingency of [redacted]

Ongoing Costs are composed of Consequential costs and contingency Single Fuel Channel Replacements (SFCR):

$M	To Enable 261k EFPH for Pickering	To Enable 235k EFPH for Darlington	Total
Consequential Costs*	52.0	23.6	75.6
Contingency repeat CT-LISS nozzle inspection	5.1		5.1
Contingency SFCR (including material surveillance)		66.0	66.0
Total	57.1	89.6	146.7

*Consequential costs are composed of: material surveillance of pressure tubes and annulus spacers post the FCLE project, incremental station OM&A for fuel channel inspection and maintenance, incremental major components (Feeders, Steam Generators) life cycle management costs.

With another CANDU operator co-funding the R&D effort at 50%, OPG's forecast expenditure would be the following:

($M)	2014	2015	2016	2017	2018	Total
Base	[redacted]					
Contingency						
Total	5.7	21.0	24.9	15.3	0.6	67.4

Approvals

	Signature	Comments	Date
This BCS represents the best option to meet the validated business need in a cost effective manner.			
Recommended by: Mark Elliott, SVP & Chief Nuclear Engineer Project Sponsor			Oct 30, 2013
I concur with the business decision as documented in this BCS.			
Finance Approval: Donn Hanbidge, SVP & Chief Financial Officer Position per OPG-STD-0076			Nov 7/13
I confirm this project will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Tom Mitchell, President & Chief Executive Officer Position per OAR, per OAR 1.1			Nov 11, 13

Final Security Classification of the BCS: **OPG Confidential**

Business Case Summary

Part A: Business Need

Business Need:

As Darlington and Pickering reactors age, OPG needs to continually update its assessments of degradation mechanisms on fuel channel components. These degradation mechanisms may impact OPG's ability to demonstrate fitness-for-service of the units and, consequently, the success of continuing to operate these units to planned end of life (EOL).

Major degradation mechanisms can be categorized as follows:

1. Effect of Hydrogen/Deuterium ingress on pressure tube fracture toughness
2. Pressure tube crack initiation by delayed hydride cracking (DHC), fatigue, or overload
3. Mobility and integrity of annulus spacers and prevention of pressure tube/calandria tube contact

Significant research and development (R&D) as well as improved methodologies such as Probabilistic Core Assessment (PCA), Probabilistic Leak Before Break (PLBB) assessments, and Probabilistic fracture protection are required, to provide OPG with assurance that its units remain fit-for-service to the end of their targeted service lives.

R&D work and technical assessments co-ordinated under the current Fuel Channel Life Management Project (FCLMP 10-62444), have enabled an improved understanding of degradation mechanisms behind the aging of fuel channel components. Under this project, high confidence has been established in the fitness-for-service of Pickering fuel channels to operate to 247k EFPH. Together with the required R&D, inspection and maintenance activities, this enables continued operation of Pickering Units (EOL 2019-2020).

At FCLMP (Project #62444) completion (mid 2015) it is expected that plans, tools, and methodologies will have been established to acquire and analyze inspection and surveillance data to assess technical confidence in the fitness-for-service of Darlington pressure tubes to 210k EFPH. A Darlington 10 year Spacer Management Plan [2] has also been submitted to the CNSC. It is expected that the confidence of Darlington operation to 210 kEFPH will be determined in 2015.

A Protocol agreement has been established with CNSC with hold points going beyond FCLMP. Some of the hold points are tied to the current Pickering Operating License [2], while others may be required for the future Darlington Operating License. In order to be released from these hold points, OPG must complete inspection, assessments and R&D activities as per the Protocol, including those specified in "Long Term Darlington Life Management Plan for Inconel X-750 Annulus Spacers" [2].

Economic value exists in OPG's ability to increase operational flexibility with respect to the sequencing and timing for the refurbishment of Darlington units. For example, refurbishment of the first unit (U2) with no overlap of the second unit refurbishment outage would require the remaining three units (with overlaps of their refurbishment outages) to operate up to and beyond 210k EFPH. This would require demonstrating capability (for the last unit to be refurbished) to operate to approximately 235k EFPH. There is also economic value in the extended operation of Pickering units to beyond 247k EFPH. For example, extended operation of all Pickering units to year end 2020 would require operation to 261k EFPH. This increased operational flexibility or opportunity for additional economic value is offset by the cost /risk of extending the understanding of the degradation mechanisms.

Surveillance testing of the PT from D1321 SFCR (spacer testing is part of FCLMP) and that of the PT and spacers from P1561 SFCR is included in the scope of this project.

BUSINESS COMMITMENTS NOT INCLUDED IN THE PROJECT:

OPG has the following commitments related to fuel channel component life cycle management beyond the FCLE project scope. These costs have been included in the economic assessment for this business case.

Type 3 Business Case Summary

1. Material Surveillance Testing of Pressure Tubes and Spacers from SFCR and D2 Refurbishment:

One (1) pressure tube removed from Darlington Unit 2 in 2017 will be subject to surveillance testing required by CSA N285.4, and surveillance testing of all 24 spacers and fractography of the tested material, which are expected to be included in the new revision of the CSA 285.4. There will also be Pressure Tubes and Spacers during later lives (1 SFCR planned for P1951, 1 SFCR to be evaluated for DNGS) requiring same testing. Conceptual estimate for these activities is $23M.

2. Incremental Station OM&A Costs for Fuel Channel Inspection and Maintenance

Includes 1 SFCR campaign at Pickering in 2019 (P1951 outage), 3 SLAR campaigns, Scrape sampling etc., for total estimated cost of $48M.

3. Additional Life Cycle Management Cost of Other Major Components due to extended operations

Estimates are: Feeders: $0.4 M; Steam Generators: $4.5 M and Reactor Components: $5.1 M, for a total of $10 M

4. Contingency SFCRs

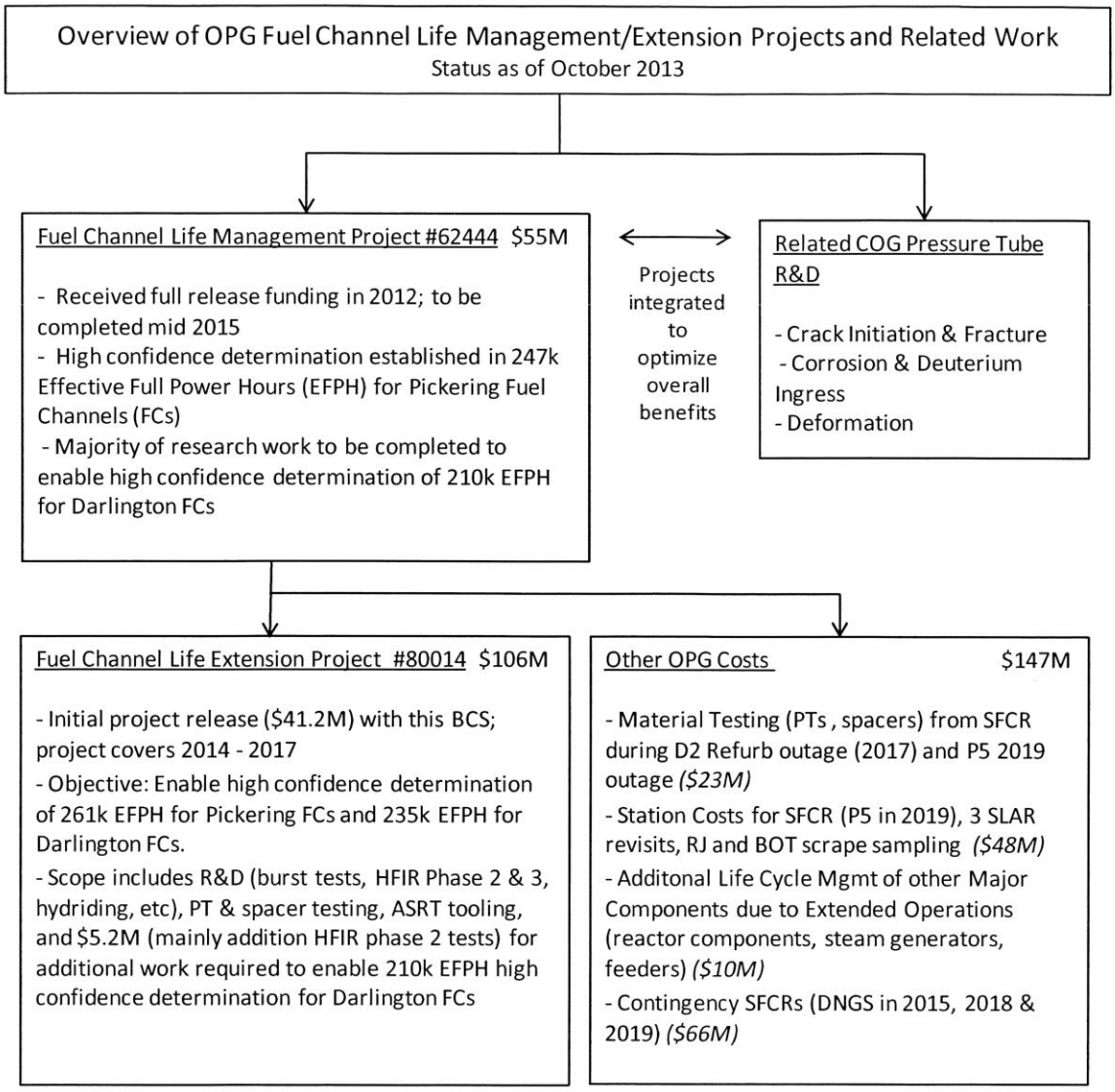
There could be three contingent SFCRs at Darlington; in 2015 (D1531 outage), 2018 (D1831 outage) and in 2019 (D1941 outage) depending on the results of earlier SFCRs related to spacer integrity assessments. Spacer testing is estimated at $2M/SFCR with a Station cost of $20M/SFCR.

5. Burst Test post 2017

Funding for additional BTs post 2017, if required.

6. HFIR Irradiation post 2017

Funding for additional HFIR post 2017, if required.



Part B: Preferred Alternative

Description of Preferred Alternative: Execution of Fuel Channel Life Extension Project

Upon completion of the project, OPG will have the plans, tools, and methodologies to acquire and analyze inspection and surveillance data to assess fitness for service of fuel channels to the targeted lives of 261k EFPH plus margin at Pickering and 235k EFPH plus margin at Darlington. This would enable OPG to achieve its business objectives for Pickering Continued Operations and the Darlington Refurbishment.

The work scoped in the BCS is also required for planning flexibility with respect to the sequencing and timing for the refurbishment of Darlington units. For example, refurbishment of the first unit (U2) with no overlap of the second unit refurbishment outage would require the remaining three units (with overlap) to operate longer. This would require demonstrating capability (for the last unit to be refurbished) to operate to approximately 235 k EFPH.

PROJECT SCOPE AND RELEASE STRATEGY

The FCLE project will be released and executed in two phases:

- Phase 1 partial release (2014-2015) to define R&D scope, to execute phase 1 of the Burst Test Matrix and Phase II of HFIR Irradiation work, and to complete surveillance testing of the PT from D1321 SFCR.
- Phase 2 final release (2016-2017) will include the BTs from the Matrix logic and HFIR as determined from the Phase I results (from BTs conducted and HFIR completed), and refinement of models and methodologies based on the R&D results, and to complete surveillance testing of the PT and spacers from P1561 SFCR. Since R&D work is planned for the full year of 2017, minor funding ($600k) is included for the project management and close-out activities in 2018.

Table 1 - Breakdown of the project work scope and estimates

Item	This Release (2014-2015)	Est. Cost	Future Release (2016-2017)	Est. Cost
Inspection & Maintenance Scoping	Complete majority of R&D, inspection and maintenance scoping including assessment of target end of life hoop stress, PT/CT contact. Pilot assessment of LBB and FP using new FT models	$2.4M	Complete remaining assessment work for the extended operations, including PCA, LBB and FP assessment using new FT models	$1.8M
Materials Testing	Complete surveillance testing of PT from D1321 SCFR and issue test reports. Complete removal and shipping to AECL of PT and Spacers from P1561 SCFR.	$3.4M	Complete surveillance testing of PT and Spacers from P1561 SCFR and issue test reports.	$4M
Core R&D	Complete 4 Burst Tests (BTs) for Fracture Toughness (FT) model validation for the extended end of life conditions (higher [H]eq and higher hoop stress)	$8M	Complete 10 BTs for FT model expansion to extended life conditions	$20M
	Hydriding to achieve 130 ppm. High Pressure Hydriding (HPH), Electrolytic and/or alternative hydriding techniques development to simulate higher [Heq] in later life reactor conditions	$3M	Hydriding to achieve 150 ppm	$2M
	High Flux Isotope Reactor (HFIR) phase II scope.	$6M	HFIR Phase III and Irradiation of spacer material and ex-service spacers	$6M
	Interim Spacer models established. Further development/refinement of the Empirical and structural models for the Darlington tight fitting spacers	$1M	Formal Spacer models established for extended life	$1M
	Other related R&D activities (Hydride Reorientation Stress, Chlorine Content etc.)	$4M	Other related R&D activities (Deuterium Ingress, Tight Fitting Spacer Movement etc.)	$3.5M
Third Party Reviews	Key submission to the CNSC on FT and Spacer models	$0.3M	Key submission to the CNSC on FT and Spacer models	$0.2M
Tooling	Advance Spacer Retrieval Tooling (ASRT) adaption for SFCR	$0.5M	Spacer Retrieval Tooling for extended life conditions	$1.5M
Other Work	OPG and COG Project management activities, development of the next BCS release in 2015 etc.	$1.7M	OPG and COG Project management activities, project close-out etc.	$2.8M

Table 2 below explains the differences between FCLMP (#62444) and this project (#80014) on the Core R&D scope items:

Item	FCLM Scope (Proj. #62444)	FCLE Scope (Proj. #80014)	Explanation
1. Fracture Toughness - Burst Tests	14 BTs have been completed with which Rev. I of the New Fracture Toughness (FT) Models have been established. 6 more BTs will be completed as part of the final BCS release.	A test matrix is being developed with initial recommendation ranging from 17 to 50 BTs (including 6 from FCLMP that will be credited towards the matrix). This BCS assumes funding for 14 BTs.	Additional BTs are required under higher [Heq], broader range of Chlorine concentrations and higher hoop stress conditions which would exist during the extended life. CNSC is closely scrutinizing the BT Matrix in evaluating the acceptance of the new FT Models.
2. PT Crack Initiation - Hydriding Techniques Development	High Pressure Hydriding targeting 150 ppm [Heq] was included.	Electrolytic Hydriding in parallel with HPH and Low Pressure Hydriding to 130 ppm [Heq] by 2015, and 150 ppm by 2017.	HPH repeatability has been poor and may not achieve the target [Heq]. Alternative processes are required to achieve ~130 ppm [Heq] by 2015 to support DNGS refurbishment planning.
3. Spacer HFIR Irradiation	HFIR piloting i.e. reactor set up, material procurement, shipping and testing of the samples removed from the first interval.	Irradiation (Neutron) cost of subsequent samples and ex-service spacers retrieved during SFCRs.	Oak Ridge National Laboratories (ORNL) did not charge for neutrons during FCLM scope which was considered R&D work. Significant neutron charges will now be levied for future OPG commercial orders.
4. Spacer Empirical & Structural Modelling	Initial development of the models	Refinement of the models and acceptance by CNSC	These models are required to predict the life of the DNGS tight fitting spacers.

The Fracture Toughness Models developed under FCLMP have not yet received CNSC acceptance. Discussions with the CNSC so far indicate that significant additional testing and analysis will be required, beyond what is scoped in the FCLM Project, to validate and to expand the models for the later life conditions at Pickering (beyond 247k EFPH) and Darlington (beyond 210k EFPH).

The protocol agreement between CNSC and OPG "Additional Protocol For Development Of Probabilistic Leak Before Break Assessments And X-750 Annulus Spacers" commits OPG to R&D, inspection and material surveillance activities that extend beyond the scope and timelines of FCLMP.

PROJECT DELIVERABLES FUNDED BY THIS RELEASE (2014-2015)

FRACTURE TOUGHNESS

- Surveillance Testing of PT from D1321
- Validate the new fracture toughness model and obtain acceptance by the CNSC.
- Third party reviews of CNSC technical submissions on Fracture Toughness

SPACERS

- Removal of the PT and spacers from P1561 SFCR, and shipping to the testing facility
- HFIR irradiation, and Empirical and Structural models refinement to achieve understanding of spacer degradation at extended life.
- Mobility and PT/CT contact assessment to support the fitness-for-service assessment of the spacers
- Submissions to the CNSC according the Darlington Long Term Spacer management plan.

PROJECT COMPLETION

Project is targeted for completion and close-out by June 2018. A PIR will be completed by June 2019.

Deliverables under this release (2014-2015):

Deliverables:	Associated Milestones (if any):	Target Date:
Flaw Assessments Completed for both Pickering and Darlington Units		Dec. 30, 2014
Contact Assessments completed for Pickering 5-8		May 31, 2015
D1321 PT Surveillance Testing Report Issued		Nov. 30, 2015
Electrolytic or alternative method to achieve hydriding to 130 ppm [Heq]		Dec 30, 2015

Part C: Other Alternatives

Base Case: Status Quo – No Project and Achieve 247k EFPH for Pickering and 210k EFPH for Darlington

NOT RECOMMENDED:

In this alternative, OPG would not fund the FCLE Project and would complete only the scope of work included in the FCLMP, which concludes in 2015. The Fracture Toughness Models developed under FCLMP have not yet received CNSC acceptance. Discussions with the CNSC so far have indicated that significant additional testing and analysis will be required, beyond what is scoped in FCLM Project, to validate and to expand the models for the later life conditions at Pickering (beyond 247k EFPH) and Darlington (beyond 210k EFPH).

The protocol agreement between the CNSC and OPG "Additional Protocol For Development Of Probabilistic Leak Before Break Assessments And X-750 Annulus Spacers" requires R&D, inspection and material surveillance activities that extend beyond the scope and timelines of the FCLMP. These activities would be funded by the project if it proceeds, otherwise they would have to be funded from other sources.

This alternative would not allow OPG to achieve its business objectives of operating Pickering to the end of 2020 and of operating the Darlington units to their currently planned refurbishment dates without incurring idle time or significant life management outages, and would significantly curtail OPG's planning flexibility with respect to the operation of Pickering and Darlington.

For example, removal of the overlap between the first and second unit refurbishments at Darlington (as is currently planned) would require the last unit to operate to approximately 230 - 235k EFPH before entering its refurbishment outage. High confidence in operating up to approximately 235k EFPH cannot be achieved with this alternative, which would also foreclose the option of operating the Darlington units for an even longer period prior to refurbishment, if it were economical to do so.

Alternative 2: NOT RECOMMENDED - Achieve 247k EFPH for Pickering and 210k EFPH for Darlington with Life Management of Darlington Units

This alternative was considered but rejected. Given the currently contemplated Refurbishment Schedule for the Darlington units, this alternative would imply either idle time of 8 months on Darlington Unit 1, 19 months on Darlington Unit 3, and 30 months on Darlington 4 prior to refurbishment, or life management of these units during 2014 to 2021/2022 to mitigate this significant idle time threat immediately prior to refurbishment, or other mitigating activities such as SFCRs, or non-standard operating configurations in the most-at-risk fuel channels.

Similarly this alternative would require life management of Pickering Unit 7 to achieve the end of 2020 along with Pickering Unit 8, and would see Pickering Units 5 and 6 cease operation in early 2020 and 2019 respectively.

While the costs of the FCLE project would be saved as well as a portion of consequential costs, significant system economic value would be forsaken. This alternative would foreclose the option of operating the Darlington units for a longer period prior to refurbishment, if it were economical to do so.

Alternative 3: NOT RECOMMENDED - Achieve 247k EFPH for Pickering and Do only R&D work to Achieve 217k EFPH for Darlington with Possible Life Management of Darlington Units

This alternative was considered but rejected. Given the currently contemplated Refurbishment Schedule for the Darlington units, this alternative would imply idle time of 7 months on Darlington Unit 3 and 18 months on Darlington Unit 4 prior to refurbishment, or life management of these units in the period 2014 to 2021/2022 to mitigate this significant idle time threat immediately prior to refurbishment or other mitigating activities, such as SFCRs or non-standard operating configurations in the most-at-risk fuel channels.

The opportunity to extract addition economic value for the system by operating all Pickering units to the end of 2020 would also be lost. This alternative would foreclose the option of operating the Darlington units for an even longer period prior to refurbishment, if it were economical to do so.

Alternative 4: NOT RECOMMENDED - Do Not Extend Pickering Fuel Channel Life Past 247 k EFPH, but Extend Darlington to 235k EFPH

The opportunity to extract addition economic value for the system by operating all Pickering units to the end of 2020 would be lost. Some of the testing which would provide high-confidence in Darlington achieving 235k EFPH also provides a benefit to Pickering and there is economic value and operational flexibility gained by operating Pickering units to the end of 2020. Thus, for a relatively small incremental cost, the FCLE project can achieve the target business objectives for both Pickering and Darlington; therefore, this alternative is not preferred.

Part D: Project Cash Flows

M$	LTD	2014	2015	2016	2017	2018	2019	Future	Total
Currently Released									
Requested Now	-	8.5	32.7						41.2
Future Required	-			37.6	26.5	0.6			64.6
Total Project Cost		8.5	32.7	37.6	26.5	0.6			105.8
Ongoing Costs	-		22.0		4.5	63.6	53.5	3.1	146.7
Grand Total		8.5	54.7	37.6	31.0	64.1	53.5	3.1	252.5

Estimate Class:	Class 4	**Estimate at Completion:**	[redacted]	**OAR Approval Amount:**	252.5

Additional Information on Project Cash Flows (optional):

Project Cash Flows, Estimate at Completion, and OAR approval amount show in the table above assumes no co-funding by any other party. The Estimate at Completion does not include contingency of [redacted]

Ongoing Costs are composed of Consequential costs and contingency Single Fuel Channel Replacements (SFCR):

$M	To Enable 261k EFPH for Pickering	To Enable 235k EFPH for Darlington	Total
Consequential Costs*	52.0	23.6	75.6
Contingency repeat CT-LISS nozzle inspection	5.1		5.1
Contingency SFCR (including material surveillance)		66.0	66.0
Total	57.1	89.6	146.7

*Consequential costs are composed of: material surveillance of pressure tubes and annulus spacers post the FCLE project, incremental station OM&A for fuel channel inspection and maintenance, incremental major components (Feeders, Steam Generators) life cycle management costs.

With another CANDU operator co-funding the R&D effort at 50%, OPG's forecast expenditure would be the following:

($M)	2014	2015	2016	2017	2018	Total
Base	[redacted]					
Contingency						
Total	5.7	21.0	24.9	15.3	0.6	67.4

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

Type 3 Business Case Summary

Part E: Financial Evaluation

M$	Preferred Alternative	Base Case	Do Less	Alternative 3	Alternative 4
Project Cost	105.8	0	N/A	N/A	
NPV (after tax)	1100	N/A	N/A	N/A	

Summary of Financial Model Key Assumptions (see Guidance on this Type 3 BCS Form):

The value to the electricity system if the Fuel Channel Life Extension (FCLE) Project is pursued and successfully achieves high confidence in fitness-for-service of the fuel channels to 261k EFPH at Pickering and to 235k EFPH at Darlington is estimated at $1.1 B (PV 2013$). This value is based on the assumption that the Darlington units are indeed operated to 235k EFPH or to their planned refurbishment dates (whichever is earlier) and that the Pickering units are operated to the end of 2020 (261k EFPH allows all units to operate to at least the end of 2020). The amount contributed by Pickering and Darlington to the overall value is shown in Table 3. As can be seen, the majority of the value arises from the elimination of the idle time on the Darlington units, which would occur if these units are refurbished on their currently planned refurbishment schedules, but fitness-for-service of the fuel channels beyond 210k EFPH were not achieved. However, there is approximately $220M (PV 2013$) in value created by the longer operation of the Pickering units. The estimated value is net of the estimated $64 M (PV 2013$) cost of implementing the FCLE project, as well as net of the estimated $77 M (PV 2013$) of consequential costs associated with longer operation and increased life cycle management work on both Darlington and Pickering.

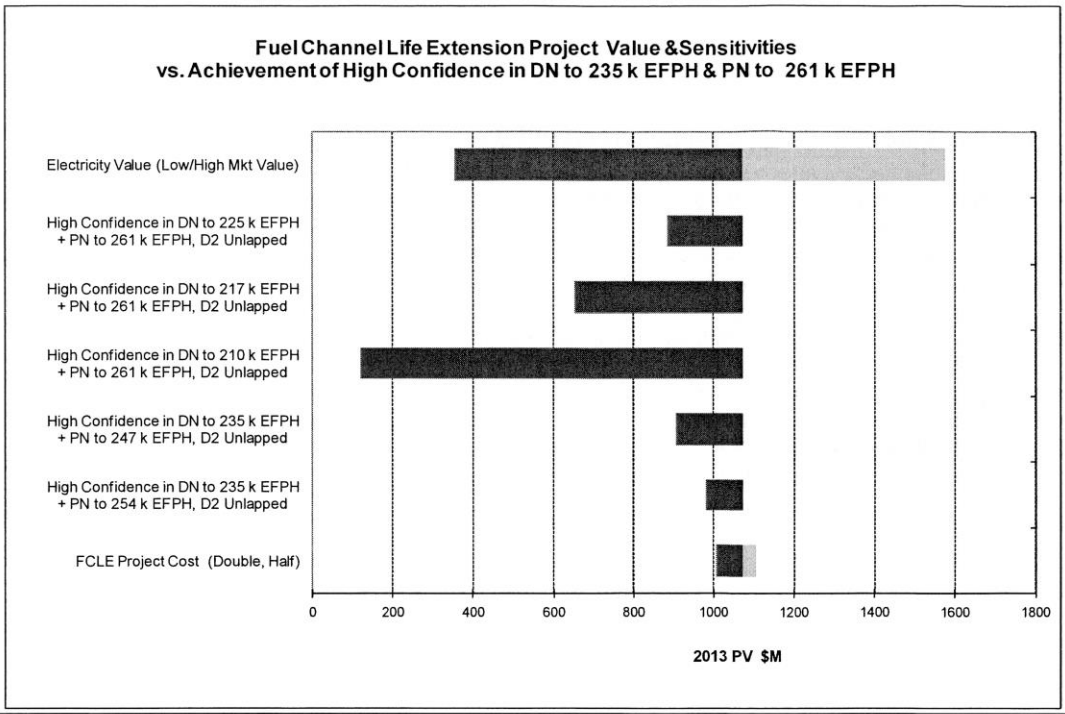
Table 3: Summary of Value Enabled by Recommended Alternative Versus Do Nothing (No project)

	No FCLE Project	Implement FCLE project	Impact	Value $B (PV 2013$)
Pickering	High Confidence in 247k EFPH achieved. Units Assumed Operated to 247k EFPH with Life Mgmt Outages on Unit 7	Tools and methodologies established to determine technical confidence in 261k EFPH achieved. Units Assumed Operated to 261k EFPH or end 2020, whichever is sooner.	Would allow all Pickering units to operate until end 2020, and would eliminate life mgmt outages on Pickering Unit 7.	0.2
Darlington	High Confidence in 210k EFPH achieved* and Units operated to 210k EFPH or start of refurbishment outages, whichever is sooner	Tools and methodologies established to determine technical confidence and Units operated to 235k EFPH or start of refurbishment outages, whichever is sooner	Would allow elimination of all idle time prior to start of refurbishment on all units, given current planning schedule. Also allows flexibility to start refurbishment of the first unit later if readiness issues arise.	0.9
			Total Median Estimated Value	**1.1**

*Some additional funding above base programs and beyond the Fuel Channel Life Management Project would be required to achieve high confidence in 210k EFPH at Darlington.

Results of the economic assessment were tested for sensitivity to key inputs such as the assumed electricity value, the degree of success in achieving high confidence in additional fuel channel life, and therefore the amount of additional station operating life achieved, the cost of the FCLE project and the level of consequential costs. In summary, the results indicate that, provided some additional life on Darlington is achieved, even if only to 217k EFPH, there would be a positive value to the electricity system, given the current planned refurbishment schedule (i.e. no overlap of the first two units to be refurbished), because of the reduction in idle time which is achieved. The following tornado diagram shows the key sensitivity results.

Figure 1: Sensitivity of Value to Key Uncertainties



The following provides additional details on the sensitivity analysis:

i. Assumed Electricity Value: The estimated value of FCLE is extremely sensitive to the assumed electricity value. In a high value regime the estimated value of eliminating potential idle time on Darlington and operating all of Pickering to end 2020 could be as high as approximately $1.6 B (PV 2013$). In a low value regime the value could be approximately $0.4 B (PV 2013$). A low priced regime could result from low or declining electricity demand growth (which could result, for example, from a prolonged economic slowdown) and low or declining gas prices, and /or high conservation which could result in a prolonged period of significant surplus base load generation.

ii. Length of Operating Life Achieved: The value is somewhat sensitive to the additional fuel channel life which can be achieved with high confidence:

- If the FCLE project were to enable the Pickering units to operate until end 2020, but only allowed Darlington to operate to 225k EFPH the value would be reduced by approximately $200 M (PV 2013$) to approximately $0.9 B (PV 2013$), as approximately 7 months of idle time would result for the last unit refurbished.
- If end 2020 operation were achieved for the Pickering units, but only 217k EFPH were achieved for Darlington the value would be reduced by approximately $425 M (PV 2013$) to approximately to $0.65 B (PV 2013$), as approximately 23 months of idle time would result on the last two units refurbished.
- If end 2020 were achieved for the Pickering units, but the FCLE project was unsuccessful and the Darlington fuel channel lives could not be extended beyond 210k EFPH, the value would be reduced by approximately $1.0B (PV 2013$) to $0.1 B (PV 2013$), as approximately 57 months of idle time could be incurred on the last three units refurbished.
- If the FCLE project achieved 235k EFPH for Darlington (no idle time) but only achieved 254k EFPH for Pickering the value would be reduced by approximately $100M (PV 2013$) to approximately $1.0 B(PV 2013$).
- If 235k EFPH were achieved for Darlington, with Pickering life remaining at 247 k EFPH, the value would be reduced by approximately $200 M (PV 2013$) to $0.9 B (PV 2013$).

iii. Project Costs: The value is insensitive to FCLE Project Costs. An approximate doubling of these costs reduces the value by $64 M (PV 2013$) to approximately $1.0 B (PV 2013$). A halving of these costs increases the value by $32 M (PV 2013$). Given the magnitude of the consequential cost the value would also be insensitive to consequential costs.

Part F: Qualitative Factors

The completion of the scope in the preferred alternative of this project is critical to the Continued and Extended Operations of Pickering, Refurbishment of Darlington. Since OPG operates the first CANDU units to be impacted by the fuel channel degradation mechanisms being investigated, our R&D findings may present financial opportunities when other CANDU units in the world are approaching their end-of-life.

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	Burst Test matrix not finalized and reviewed with CNSC. Additional BTs may be required (in excess of 14 included in the scope)	Contingency has been included for moderate scope addition	Medium	Medium
Scope	Same as above	to be finalized in the next BCS release	Medium	Low
Schedule	Same as above	Schedule extension - to be finalized in the next BCS release	Medium	Medium
Resources	Delay in project schedule may occur due to unavailability of specialized resources who cannot be easily replaced. Reasons may include labour disputes or commitment to other work programs in the vendor company	Mitigate - Obtain resource commitment from vendors Accept risk if resource unavailabiliy is due to labour disputes	Low	Medium
Quality/ Performance	If the empirical and structural modelling work conducted at Oak Ridges National Laboratory cannot provide predictive capability of spacer material degradation, the confidence in spacer material conditions may be uncertain.	Mitigate - Insufficient prediction capability will need to be made up by additional spacer material surveillance, with contingent Darlington SFCR's required	Medium	Medium
Technical	Results of R&D or field inspection may not support operations to the targeted fuel channel lives (235k EFPH for Darlington and 261k EFPH for Pickering)	Mitigate - Phased release strategy and continuous assessments of the R&D and inspection results to minize the cost of the project should this risk materialize	Medium	Medium

Cost	Increase in cost due to R&D vendor switching their cost model for full cost recovery - future quotes from R&D vendor may be higher than anticipated	Specific escalation contingency and a small [redacted] general contingency has been included in the project has been included	Med	Low
Scope	Increase in cost due to discovery work scope, indeterminate results or unexpected results. This also affects cost and schedule.	Mitigate - Set aside contingency on COG Joint Project Work.	Med	Med
Scope	Unexpected scope cuts from the outage will cause the project to have insufficient information to perform assessments on fuel channel fitness-for-service	Mitigate - Communicate to the outage planning organization that work is essential to the continued operation of the stations	Low	Med
Quality	Insufficient pressure tube test material available - may reduce confidence in fracture toughness models	Specific contingency [redacted] has been set aside for procurement of ex-service tubes from other CANDU plants	Low	Med

Additional Risk Analysis:

Long term business risk to demonstrate fuel channel fitness-for-service (post project):
Management of fuel channel fitness-for-service must continue even after the completion of this project. As units age, CNSC is expecting that there would be sufficient inspection and surveillance data to support the projections that the units are safe to operate to their targeted service lives. An expansion of fuel channel inspection scope has been proposed to the outage organization with the potential for outage extension. A Darlington "Long Term Spacer Plan" has also been submitted to CNSC, stating OPG's plan to retrieve and test intact spacers from Single Fuel Channel Replacement campaigns in outages, as well as during Darlington's 1st Unit Refurbishment.

Part H: Post Implementation Review (PIR) Plan

Type of PIR	Target Project In Service Date	Target PIR Completion Date
Simplified	2018-06-30	2019-06-30

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Expanded fracture toughness curves covering the hydrogen concentrations at extended life	FCLMP may obtain CNSC acceptance of the new fracture toughness models, but will not cover the later life conditions	Expanded fracture toughness curves reflecting effects of hydrogen concentration, covering lower-shelf and transition temperature region	Acceptance of the expanded fracture toughness curves by the CNSC.	MCED
Structural model to project Darlington Spacer life limits	No model available	Model developed and available for use	Acceptance by CNSC	MCED
Confidence in fitness-for-service of the Pickering fuel channels to 261k EFPH is established	Confidence statement not available	Level of confidence established and statement available	Fuel Channel experts concur with High Confidence	MCED
Confidence in fitness-for-service of the Darlington fuel channels to 235k EFPH	Confidence statement not available	Level of confidence established and statement available	Fuel Channel experts concur with High Confidence	MCED

Type 3 Business Case Summary

Part I: Definitions and Acronyms
ASRT - Advanced Spacer Retrieval Tool
BT - Burst Test
CT - Calandria Tube
EFPH - Equivalent Full Power Hours
FCLE(P) - Fuel Channel Life Extension (Project)
FCLM(P) - Fuel Channel Life Management (Project)
FT- Fracture Toughness
HFIR - High Flux Irradiation Reactor
HPH- High Pressure Hydriding
PM - Project Management
SFCR - Single Fuel Channel Replacement
SLAR - Spacer Location and Repositioning

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OPG-FORM-0076-R003*

Type 3 Business Case Summary

Appendix A: Summary of Estimate										
Project Number:	10-80014		**Facility:**	Nuclear						
Project Title:	Fuel Channel Life Extension Project									
Estimated Cost in M$										
	LTD	**2014**	**2015**	**2016**	**2017**	**2018**	**20--**	**Future**	**Total**	**%**
OPG Project Management		0.6	0.6	0.8	0.8	0.4			3.3	4.5
OPG Engineering		0.3	0.7	0.6	0.4	0.1			2.1	2.8
Permanent Materials			0.5	2.2	0.5				3.2	4.3
Design and Construction										
Consultants		[redacted]							[redacted]	
Other Contracts/Costs										
Interest										
Subtotal without Contingency		[redacted]							[redacted]	
Contingency										
Grand Total		**8.5**	**32.7**	**37.6**	**26.5**	**0.6**			**105.8**	

Notes			
Project Start Date	2014-01-02	**Project Completion or In-Service Date**	2018-06-30 (FCLE Project Completion)
Interest Rate	5.00%	**Escalation Rate**	2.0%
Definition Cost Included	$0 k	**Estimate at Completion**	[redacted]

Prepared by:		**Approved by:**	
John Xiao Section Manager, FCLMP	2013-10-28 YYYY-MM-DD	Kathy Charette Director (Acting), FCLMP N.C. VAN DEN BREKEL ACTING FOR K. CHARETTE	2013-10-28 YYYY-MM-DD

Type 3 Business Case Summary

Appendix B: Comparison of Total Project Estimates										
Phase	Release	Date (YYYY-MM-DD)	Total Project Estimate in M$ (by year including contingency)						Later	Total Project Estimate
			2014	2015	2016	2017	2018	2019		
Definition & Execution	Partial	2013-11-11	8.5	32.7	37.6	26.5	0.6			105.8

Type 3 Business Case Summary

Project Variance Analysis					
Estimated Cost in M$					
M$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
First release – Project Variance Analysis not required					

Type 3 Business Case Summary

Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

Project Cost:

(1) Incremental Project Costs are [redacted] for the Preferred Alternative.

(2)

(3)

Financial:

(1) Discount rate is 7% for regulated assets.

(2)

(3)

Project Life:

(1)

(2)

(3)

Energy Production:

(1)

(2)

(3)

Operating Cost:

(1)

(2)

(3)

Other:

(1)

(2)

(3)

Attach further detail as appropriate from the Financial Evaluation spreadsheet.

Appendix D: References

1. N-CORR-00531-06249, Fuel Channel Life Management Project - Additional Protocol For Development Of Probabilistic Leak Before Break Assessments And X-750 Annulus Spacers

2. NK38-PLAN-31160-10000, Long Term Darlington Life Management Plan for Inconel X-750 Spacers

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

1/ RECOMMENDATION:

We recommend approval of the release of $33.2M (including contingency), for a total release of $63.1M. This will allow the Environment Qualification (EQ) Closure and Component Replacement Project to complete the remaining component replacements which have been committed to the Canadian Nuclear Safety Commission (CNSC) and environmental qualification completion assurance activities. It will also permit the project to determine the most efficient means for maintaining full compliance with the environmental qualification requirements of the Darlington Nuclear operating license; and allow for preliminary engineering activities to begin for new EQ issues identified during this process.

The business objective of this project is to align Darlington systems and components with the EQ requirements of its Power Reactor Operating License (PROL). Action Assignment # 28058364 has been raised to track the completion of a Regulatory Commitment (REG C) made to the CNSC for the replacement of non-qualified components with EQ-qualified components by December 31, 2010.

A total of $29.9M was previously released in accordance with Organizational Authority Register (OAR) element 1.1. The funding was used to:

1. Complete designs associated with regulatory committed component replacements.
2. Replace components in the field in 2005, 2006 and 2007 as per the regulatory committed schedule.
3. Complete EQ List Development Packages (to be completed in November 2007)
4. Complete an EQ Program Self Assessment.
5. Complete a scope optimization study (to be completed in October 2007).

This request is to:

1. Replace the remaining components in the field in 2008, 2009 and 2010 as per the current regulatory committed schedule.
2. Carry out completion assurance activities for the components which have been replaced during the project and for those not expected to be affected by the scope optimization study.
3. Complete analysis to determine the most efficient means for Darlington Nuclear to meet the EQ requirement of its operating license. Develop the scope and business case for a new project to resolve new EQ issues arising from this analysis, if required.
4. Complete the transition the Project to the Station Sustaining EQ Program.

This release does not include any future detailed design, analysis or field work required to resolve anomalies outside of the scope currently committed to the CNSC, as shown in Attachment "D".

$M (incl contingency)	Funding	LTD 2007	2008	2009	2010	2011		Later	Total
Currently Released	Partial	26.7	3.2						29.9
Requested Now	Full		11.3	10.7	10.4	0.8			33.2
Future Funding Req'd									-
Total Project Costs		26.7	14.5	10.7	10.4	0.8	-	-	63.1
Other Costs									-
Ongoing Costs									-
Grand Total		26.7	14.5	10.7	10.4	0.8	-	-	63.1
Investment Type: Regulatory		Class: OM&A		(IEV) Impact on Ec Value (38)		IRR: N/A		Discounted Payback: N/A	

Submitted By:

Wayne Robbins 2007-11-12

W. Robbins Date:
Senior Site Vice-President Darlington

Finance Approval:

D. Power 2008-01-03 Date:
Vice-President Corporate Investment Planning

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

J. Hankinson 2008/01/27 Date:
President & Chief Executive Officer

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 License Condition 7.1, Darlington must implement a program that is traceable, auditable and meets the OPGN requirements for EQ.

Requirements for Environmental Qualification (EQ) at Darlington Nuclear Generating Station (DNGS) were first spelled out in the Construction License and then formalized in 1978 with the first issue of the Design Guide. The "science" of 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 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 Power Reactor Operating License (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, the current project, 16-38457 EQ Closure and Component Replacement was initiated to resolve the outstanding issues by December 31, 2010.

Under this project (16-38457), Darlington has followed the OPGN EQ list development process, as was done at the Pickering and Bruce sites, to update its EQSRCL; this process provides full traceability and compliance with the EQ design basis. During this exercise unqualified components that were not in the Darlington EQ program have been identified. As a result of these discoveries and other deficiencies the Senior Site Vice-President instructed the project to initiate a Darlington EQ Program Self-Assessment in 2006. One of the actions coming out of the self-assessment was the requirement for the EQ Project to perform a scope optimization study with the goal of identifying ways to reduce the scope and/or the cost of EQ.

The scope optimization study is scheduled to be completed in October 2007 at which time the recommendations will be used by the EQ Project and Darlington management to determine the most practical and economical path forward for EQ at Darlington.

Major deliverables achieved under previous releases of this project were:

1. Completion of EQ List Development Packages (TCD: November 30, 2007).
2. Completion of committed D541, D611, D631, D741, and D721 outage work (On track as per N-PROC-MA-0013).
3. Completion of committed 2007 online work (On track as per N-PROC-MA-0022).
4. Completion of design packages for remaining committed outage and online work (including discovery items for Limitorque actuators and ITT Cannon connectors - U1 packages complete, TCD for remaining packages: March 20, 2008).
5. Completion of an EQ Program Self-Assessment (Complete).
6. Completion of a scope optimization study (TCD: October 26, 2007).

The previous BCS (Ref. 7) was prepared prior to the current revision of the project charter (Ref. 6) which increased the scope of the project as described below:

1. Additional components which need to be replaced in the field were identified as a result of additional EQLDP packages being completed. (Only components currently committed to the CNSC, as detailed in Attachment "D", will be completed in this project)
2. It was identified that the transition to the EQ sustaining program will require a higher level of effort than originally anticipated from the project.
3. Requirement added to complete a scope optimization study.
4. Requirement to study fiber optical cables and determine a practical method to resolve the issues surrounding the requirement for them to be EQ. (This will not be addressed under this project.)
5. Requirement added to perform completion assurance activities for all EQ components. (In this project, completion assurance activities will only be completed for the components replaced under this project and those not expected to be affected by scope optimization.)

These changes have caused a small increase to the original cost estimate prepared under the previous BCS (Ref. 7), a new project is also expected to be required to address the deficiencies not covered by this project and new deficiencies which may be identified in the future.

In March 2007 the CNSC conducted an audit of Darlington's EQ program. The audit report (Ref. 5) has been sent to Darlington with several action notices and recommendations, the following are relevant to the EQ project:

- AN2 - Based on the requirements of OPG Environmental Qualification Program, N-PROG-RA-0006 and OPG procedure, N-PROC-RA-0092, Environmental Qualification Implementation and Preservation DNGS is required to expeditiously complete the Technical Basis Documents (TBD), EQSRCL, EQLDPs, EQAs, EQ cables list and On-Line Wiring. DNGS is also required to prepare an auditable EQSRCL, with sufficient references to basis documents and guidance for, how to fill and read this list.

- AN3 - CNSC inspectors observed lot of inconsistencies in the various documents as identified in Section 4.2 (of Ref. 5). DNGS need to revise these documents (EQ design guide, EQLDPs, EQA, EQSRCL, FIN procedure and EQLDP procedure).

- AN5 - DNGS has not qualified the fiber optic cables. We require DNGS to provide a schedule for the completion of EQ of the fiber optic cables.

- R4 - CNSC recommend DNGS that soon after the completion of all EQLDPs, the EQ RCM to be revised to provide conditions for all new rooms and areas, if needed.

3/ ALTERNATIVES AND ECONOMIC ANALYSIS

$ Millions	Stop the Project	Alt 1 (Recommended)		Alt 2	Alt 3	Alt 4	Alt 5
		Full Cost	Incremental Cost	Delay	Do Less	Do More	
Revenue	-	-	-				
OM&A	(2.67)	(63.11)	(39.08)	N/A	N/A	N/A	
Capital	-	-					
NPV (after tax)	(1.70)	(37.71)	(22.08)				
Impact on Economic Value (IEV)	N/A	(36.01)	(20.38)				
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. This would result in the outstanding committed scope of work to remain incomplete; as a result the REG C commitment would not be met.

Alternative 1 - Complete Committed Replacements & EQ Efficiency Analysis - Recommended
Completing committed component replacements (including completion assurance) and determining the most efficient means for maintaining full compliance with the EQ requirements of the license is recommended. The work is required to bring Darlington in compliance with its PROL and the failure to do so would result in the CNSC REG C remaining incomplete.

In order for Darlington to be successful in meeting its regulatory commitments it is critical that the installation activities for the committed scope of work continue as scheduled in parallel with the scope optimization study and other activities required to determine the most effective path forward for EQ at Darlington.

Alternative 2 - Delay Project - Not Recommended
Delaying the project is not recommended. The component replacements which are being done under this project have been committed to the CNSC for completion by December 31, 2010 under Action Assignment # 28058364.

Alternative 3 – Do Less - Not Recommended
Completing component replacements and not doing the EQ efficiency analysis is not recommended as it would jeopardize Darlington's ability to meet its regulatory commitment. The components which are being replaced in the field under this release are only those which have been previously committed to the CNSC (refer to Ref. 1 and Attachment "D"). The additional work being done is required to determine the best path forward for Darlington to comply with its PROL.

The project is making extensive use of Operating Experience (OPEX) from the Pickering and Bruce sites to ensure that the requirements of the Ontario Power Generation Nuclear (OPGN) EQ Program and Darlington's PROL are met at minimum cost.

Alternative 4 – Do More - Not Recommended
Due to the number of unknowns associated with maintaining full compliance with EQ requirements of the license, it is recommended at this time to release an additional $33.2M to allow the committed scope of work to be completed in accordance with the schedule. It will also allow the design basis documentation to be completed and an analysis to determine the most efficient method for maintaining full EQ compliance; if future work is found to be required for Darlington to meet its PROL it will be completed under a separate project.

Alternative 5 – - Not Recommended

4/ THE PROPOSAL

The proposal is for the full release of $33.2M to allow the Environmental Qualification (EQ) Closure and Component Replacement Project to:

1. Continue work on the following activities that are critical to the REG C committed schedule (Attachment "D"):
   a. Replace components in the field during the D811, D931, D1041, and D1021 outages.
   b. Replace components in the field in 2008 through 2010 via the Darlington online program.

2. Prepare completion assurance packages for the components replaced during the project and for those not expected to be affected by the scope optimization study (~ 4000 tags). Address completion assurance requirements for cables.

3. Determine the most cost effective and efficient method for Darlington Nuclear to comply with the EQ requirements in its operating license by December 31, 2010, through the following activities:
   a. Preparation of draft EQ Technical Basis Documents and initiation of the station review of them.
   b. Initiation of a gapping analysis to determine the components which, in order to comply with EQ governance, require:
      i. Modifications.
      ii. Replacement, due to them being beyond their qualified life span.
      iii. Documentation updates.
      iv. Qualification testing.
   c. Use the scope optimization study as a cost benefit tool to determine the most efficient path forward for Darlington to comply with the EQ requirements of its PROL.

4. Initiate preliminary design / analysis / testing activities for deficiencies identified in the gap analysis and the selected scope optimization options (this may include procurement of long lead time materials). This includes, but is not limited to:
   a. Qualification of column line 11 as a steam barrier.
   b. Modification(s) required to address concerns with wet rooms.
   c. Qualification / replacement of BIW cables outside containment.

   Detailed engineering activities, procurement of short lead time materials and installation activities for this new scope will not be completed under this project. If required, the business case for a new project to resolve the new EQ issues arising from this new scope will be developed.

5. Complete the transition to the Sustaining EQ Program, this will be done through mentoring, transfer of software tools to the sustaining staff and preparation of desktop guides to promote the consistent application of EQ.

NOTE:
The correction of any configuration management issues identified during completion assurance walk-downs is not within the scope of this project.

The Project Execution Plan will be approved by December 2007.

5/ QUALITATIVE FACTORS

Environmental Qualification compliance and sustainability are licensing 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.

6/ RISKS

Description of Risk	Description of Consequence	Risk Before Mitigation	Mitigating Activity	Risk After Mitigation
Cost				
Underestimation of cost.	Higher cost.	**Medium**	TIS sheets, issued contracts and actuals for similar tasks were used in the preparation of the estimate, general contingency has been included to cover possible cost increases. A independent agency has been contracted to review the estimate for accuracy.	**Low**
Complete scope of activities for Darlington to comply with it's PROL not defined.	A new project may be required for Darlington to comply with its PROL. Current conceptual estimates for this project are in the range of $40M to $140M.	**Low**	Included in the scope of this project is a scope optimization study whose purpose is to find ways to reduce the overall scope and cost of EQ for Darlington.This project will only complete the scope of work detailed in section 4, any additional work required for Darlington to comply with its PROL will be managed through a new project, the new project will provide a detailed cost estimate for this new scope.	**Low**
More scaffolding required than estimated.	Higher cost.	**Medium**	Funding has been included in the estimate for scaffolding and general contingency is available for possible cost increases.	**Low**
Scope				
Configuration management issues identified during completion assurance walk-downs.	Challenge to schedule, increased station OM&A costs. Based on OPEX there is a risk that correction of these deficiencies could cost up to $50M.	**N/A**	Configuration management rework issues are not within the scope of this project however the risk remains for Darlington. A sample set of walk-downs under a "pilot project" will be completed to establish a better estimate for the amount of rework that Darlington should expected.	**N/A**

Complete scope of activities required for Darlington to comply with its PROL not defined.	A new project may be required for Darlington to comply with its PROL.	**Low**	Included in the scope of this project is a scope optimization study whose purpose is to find ways to reduce the overall scope and cost of EQ for Darlington. This project will only complete the scope of work detailed in section 4, any additional work required for Darlington to comply with its PROL will be managed through a new project. This new project will provide a completion date for the new scope.	**Low**
Uncertainty on the scope of the configuration walk downs.	Higher cost.	**Medium**	Specific contingency has been included to reduce the risk associated with walk downs.	**Low**
Schedule				
Delay in the schedule, increased cost, and missed REG C commitments.	Delay in the schedule, increased cost, and missed REG C commitments.	**Medium**	All work required to be completed under this project, as outlined in Attachment "D", has been scheduled in accordance with OPG governance. Adherance to this schedule is monitored regularly by the project and any threats will be communicated to Darlington management in a timely fashion.	**Low**
Complete scope of activities for Darlington to comply with it's PROL not defined.	Inability to complete full scope of work by December 31, 2010. Until the full scope of work required for Darlington to comply with the EQ requirements of its PROL is defined and understood a completion date cannot be provided.	**Low**	Current committed scope of work (as shown in Attachment "D") has been planned and scheduled to ensure its completion by December 31, 2010. A scope optimization has been initiated in order to find ways to reduce the overall scope. Once the full scope of work required to EQ Darlington is understood a new project may be required. In order to prevent delays funding has been included in this release to initiate preliminary engineering / analysis / testing activities prior to the initiation of the new project.	**Low**
Configuration management issues identified during completion assurance walk-downs.	Increased scope of work for station resources. If this work is not completed prior to Dec. 31, 2010 there will be a list of open items turned over to the station.	**N/A**	Configuration management rework issues are not within the scope of this project however the risk remains for Darlington. Walk-downs will be scheduled as early as possible to maximize the time available to station resources for the correction of any issues identified.	**N/A**

Resources				
Availability of qualified EQ staff.	Delay in the schedule.	**Medium**	The project has retained augmented staff with EQ expertise. The corporate strategy with respect to the use of augmented staff remains a risk however CNE agreement has been obtained that the EQ project will be permitted to use augmented staff. Managed task contracts will be used to obtain qualified personnel as required.	**Low**
Availability of qualified Design Agencies & station resources.	Delay in the schedule.	**Medium**	The use of preferred vendors is being used to mitigate the risk of Design Agencies not able to support the work due to a lack of internal resources. The project has obtained the Senior Site VP agreement to the priority of the project and signed TIS sheets have been obtained from key support organizations.	**Low**
Availability of station resources (Regulatory Affairs, Nuclear Safety, Plant Design) to TBD preparation.	Delay in the schedule.	**Medium**	The project has obtained the Senior Site VP agreement to the priority of the project. Agreement has been obtained from Regulatory Affairs, Nuclear Safety and Plant Design Managers.	**Low**
Technical				
Modifications do not meet performance requirements.	Additional cost and schedule delays due to rework.	**Medium**	The use of OPEX, regular technical reviews, and the application of lessons learned is being used to mitigate this risk.	**Low**
Regulatory				
New CNSC action items being imposed on Darlington as result of the March 2007 audit results being published.	Scope, Cost and schedule increases.	**Medium**	Regular communication and update with the CNSC. Potential scope additions resulting from the recently completed audit will be managed through a new EQ project.	**Low**
		Medium		**Low**
Environmental				
N/A.	N/A.	**N/A**	N/A.	**N/A**

Health & Safety				
Workplace injury or MRPH event.	1. Injury to workers. 2. Impact to the project schedule and cost.	**Medium**	Installations will be executed under approved work practices, OPG saftey requirements, and OPG oversite.	**Low**
High radiation fields in work areas.	Field resources could reach their one and/or five year limits on radiation dose.	**Medium**	ALARA principles are applied during work planning / execution.	**Low**
Investment				
Risk of rework and/or the implementation of unnecessary modifications.	Higher cost.	**Medium**	Work in this release incorporates OPEX and is required for compliance with the EQ requirements of Darlington's PROL. A scope optimization study is being completed to ensure that unnecessary work is not completed.	**Low**

7/ POST IMPLEMENTATION REVIEW PLAN

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date:	PIR Responsibility (Sponsor Title)
Simplified	Dec 2010	Dec 2011	Director of Engineering - Darlington Nuclear

Comments:

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure it? (person / group)
1.	Completion of CNSC REG C committed component replacements, Action Assignment #28058364.	As of Jan. 2007 the committed component replacements (as documented in Action assignment # 28058364) had a due date was December 31, 2010.	Completion of committed component replacements by December 31, 2010. See Attachment "D".	Completion letter submitted to the CNSC.	Regulatory Affairs Manager
2.	No EQ issues on the committed component replacements.	EQ Completion Assurance not completed on committed component replacements.	EQ Completion Assurance on committed component replacements.	EQ Completion Assurance documents in place for all replaced components.	Components & Equipment Manager
3.					
4.					
5.					

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

AFS:	Available for Service
BCS:	Business Case Summary
BTU:	Building Trades Unions
CNSC:	Canadian Nuclear Safety Commission
EQ:	Environmental Qualification
EQA:	Environmental Qualification Assessment
EQLDP:	Environmental Qualification List Development Package
EQSRCL:	Environmental Qualification Safety Related Components List
IEV:	Impact on Economic Value
IRR:	Internal Rate of Return
LTD:	Life to Date
MRPH:	Maximum Reasonable Potential for Harm
N/A:	Not Applicable
NPV:	Net Present Value
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
PIR:	Post Implementation Review
PROL:	Power Reactor Operating License
PWU:	Power Workers Union
REG C:	CNSC Regulatory Commitment
SCR:	Station Condition Record
TBD:	Technical Basis Document
TIS:	Task Identification Sheet

ONTARIO POWER GENERATION

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BUSINESS CASE SUMMARY	

Appendix "B" **Project Funding History**

$ Millions		All Existing and Planned Releases (incl contingency) Cumulative Values									
Release Type	Month	Year	2004	2005	2006	2007	2008	2009	2010	Later	Total
Developmental	Oct	2004	4.56	2.64							7.20
Partial	Feb	2006	0.59	5.81	4.10						10.50
Partial	Apr	2006	0.59	5.81	11.52	6.95	1.25	1.25	2.50		29.87
Full	Nov	2007	0.59	5.81	8.52	11.78	14.45	10.73	10.41	0.83	63.11
											0.00
											0.00
											0.00
											0.00
LTD Spent	Aug	2007	0.59	5.81	8.52	7.61					22.53

Comments:

Appendix "C" Financial Model – Assumptions

Project Cost Assumptions:
The project cost for the committed scope of work was developed using estimates from the supporting work groups combined with historical charges against this project. The quality for this portion of the estimate is in the +30% to -15% range.

The remaining portion of the funding released under this BCS will be used to:

1. Perform completion assurance activities for the components replaced during this project and for those not expected to be affected by scope optimization. This is expected to involve:
    a. Walk-downs of ~4000 components and up to 9300 cables.
    b. PASSPORT updates.
    c. Documentation updates.
2. Determine the most cost effective and efficient method for Darlington Nuclear to comply with its operating license requirements for EQ by December 31, 2010.
3. Compete preliminary engineering / analysis / testing activities for newly identified scope. Money has been included for this activity only in 2008, it is expected that a new project will be initiated by Q4-2008 which will then be responsible for this scope of work.

There is greater uncertainty in this portion of the estimate which is mitigated by the inclusion of specific contingency for completion assurance walk downs and the overall value of the general contingency.

Financial Assumptions:
The PV_{Base} has been set to $0 for this project since completing this project is a CNSC Regulatory commitment and not doing the project is not a viable alternative.

Project / Station End of Life Assumptions:
Darlington's end of life was assumed to be 2020.

Energy Price / Production Assumptions:
N/A.

Operating Cost Assumptions:
N/A.

Other Assumptions:
It was assumed that the EQ project will be split from Darlington Design Projects prior to 2008, as a result overhead costs for a Stratum IV manager, an Administrative Assistant and a new Stratum III manager have been included in the estimate.

A new project is expected to be initiated by Q4-2008 at which time it was assumed that overhead costs would be shared by the two projects.

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BUSINESS CASE SUMMARY	

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

Attachment "A" **Project Cost Summary**

$Millions OM&A	LTD Prior Yr 2006	2007	This Release 2008	This Release 2009	This Release 2010	This Release 2011		Later	Total
Project Management (OPG)	1.08	0.52	1.54	0.90	0.90	0.44			**5.37**
Engineering & Drafting (OPG)	0.81	0.57	1.30	0.48	0.35	0.14			**3.65**
Material	0.75	1.20	0.74	0.46	0.26				**3.41**
Installation – PWU, BTU	2.20	2.09	1.74	1.03	1.35				**8.40**
Contract - Design			0.50						**0.50**
Contract - Installation	0.41	2.26	2.58	1.11	1.93				**8.29**
Contract - Other	5.01	3.27	1.90	1.80	1.10				**13.07**
Augmented Staff	4.67	1.87	1.96	1.21	0.82				**10.52**
									-
Interest (Capital Project Only)									-
Project Costs (excl contingency)	**14.92**	**11.78**	**12.25**	**6.98**	**6.71**	**0.58**	**-**	**-**	**53.21**
General Contingency			2.00	2.50	2.70	0.25			**7.45**
Specific Contingency			0.20	1.25	1.00				**2.45**
Project Costs (incl contingency)	**14.92**	**11.78**	**14.45**	**10.73**	**10.41**	**0.83**	**-**	**-**	**63.11**
2008-2012 Business Plan	14.93	11.78	5.40	5.20	5.50	6.90			**49.71**
Variance to Business Plan	**(0.01)**	**-**	**6.85**	**1.78**	**1.21**	**(6.32)**	**-**	**-**	**3.50**
Committed Cost									-
Inventory Write Off Required									-
Spare Parts / Inventory									-
Total Release (excl contingency)	**14.92**	**11.78**	**12.25**	**6.98**	**6.71**	**0.58**	**-**	**-**	**53.21**
Total Release (incl contingency)	**14.92**	**11.78**	**14.45**	**10.73**	**10.41**	**0.83**	**-**	**-**	**63.11**

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

Basis of Estimate					
Design Complete	100%		Quality of Estimate	Budget + 30% to - 15%	
3rd Party Estimate	No	OPEX used	Yes	Lessons Learned	Yes
Reviewed by Sponsor	Yes	Budgetary Quote(s)	Yes	Phase 1 Actual Used	Yes
Similar Projects	Yes	Contracts in place	Yes	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:
B. Beaudette
Project Manager
Date: 01NOV2007

Approved By:
T. Chong
Eng & Mods Manager (Strat IV)
Date: 01 Nov 2007

DNGD: EQ Closure and Component Replacement Project 16 - 38457

Full Release Business Case Summary D-BCS-03651-10004-R000

Attachment "B" **Project Variance Analysis**

OM&A	LTD Aug 2007	Full Release		Variance	Comments
		Last BCS Apr 2006	This BCS Nov 2007		
Project Management (OPG)	1.38	1.39	**5.37**	3.98	See below
Engineering & Drafting (OPG)	1.19	0.60	**3.65**	3.05	See below
Material	1.58	7.98	**3.41**	-4.57	See below
Installation – PWU, BTU	3.55	2.76	**8.40**	5.64	See below
Contract - Design			**0.50**	0.50	See below
Contract - Installation	1.69	3.56	**8.29**	4.73	See below
Contract - Other	7.25	6.07	**13.07**	7.00	See below
Augmented Staff	5.90	5.10	**10.52**	5.42	See below
Future Funding Req'd		27.13		-27.13	See below
Interest (Capital Project Only)				0.00	
Project Costs (excl contingency)	**22.53**	**54.59**	**53.21**	**-1.38**	**See below**
General Contingency		**2.41**	**7.45**	5.04	See below
Specific Contingency			2.45	2.45	See below
Project Costs (incl contingency)	**22.53**	**57.00**	**63.11**	**6.11**	See below
Committed Cost				0.00	
Inventory Write Off Required				0.00	
Spare Parts / Inventory				0.00	
Total Release (incl contingency)	**22.53**	**57.00**	**63.11**	**6.11**	
Total Release (excl contingency)	**22.53**	**54.59**	**53.21**	**-1.38**	

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

Comments:

Explanation of Variance:

The previous Partial Release BCS had an overall estimate of $27.1M for future release; it did not break down the estimate into the various categories. Hence, the high variances between the Last BCS and This BCS for the categories.

The project has achieved savings of approximately $4.9M through scope reductions relating to the Limitorque Actuators and PAWCS heat Exchanger packages.

Additions in scope including the ITT Cannon work and the increased number of Deltrol / Norgren valves which required modifications added approximately $5.0M to project costs. 60 addition EQLDP packages were also completed at a cost of $0.9M. The scope optimization study which was completed at the request of the Senior Site VP added $0.85M to the project's cost. Given the uncertainty surrounding completion assurance activities a specific contingency of $2.45M has been included.

$0.5M has been included to allow the project to initiate preliminary engineering activities to begin of newly identified scope of work prior to the establishment of the new project.

Additionally issues such as delays in obtaining vault access during outages, high radiation fields and legacy issues discovered during the project have caused challenges to the project team leading to increased costs.

Attachment "C" **Key Milestones**

Completion Date			Description
Day	Mth	Yr	
07	Jan	2008	PMM: Conceptual Design Input Complete (Scope Optimization)
19	Jan	2008	DCP: Design Pkgs App'd & issued – ITT Cannon Connectors (Online)
16	Feb	2008	LLA: Mat'l Contracts Awarded for D931S Outage
28	Mar	2008	SOI: Start of Installation for D811S Outage
15	Apr	2008	PTA: Passport Tasks set to Ready – Limitorque Valves (Online)
16	Apr	2008	DCP: Design Packages Approved & Issued for D931S Outage
16	May	2008	ICA: Installation Contracts Awarded for D931S Outage
30	Jun	2008	AFS: D811S Outage
07	Jul	2008	SOI: Start of Installation – Limitorque Valves (Online)
07	Jul	2008	PMM: Preliminary Design Input Complete (Scope Optimization)
25	Jul	2008	SOI: Start of Installation – A/L Hoses (Online)
20	Aug	2008	SOI: Start of Installation – ITT Cannon Connectors (Online)
15	Sept	2008	ICA: Installation Contracts Awarded for 2008 Online Packages
18	Sept	2008	PTA: Work Package Assessments Complete for D931S Outage
28	Oct	2008	PTA: Work Package Assessments Complete for 2008 Online Packages
19	Dec	2008	AFS: 2008 Online Packages
26	Jan	2009	LLA: Mat'l Contracts Awarded for D1041S Outage
30	Jan	2009	SOI: Start of Installation – Gould Transmitters (Online)
05	Mar	2009	ICA: Installation Contracts Awarded for D1041S Outage
20	Mar	2009	DCP: Design Packages Approved & Issued for D1041S Outage
16	Apr	2009	SOI: Start of Installation for D931S Outage
11	Jul	2009	AFS: D931S Outage
01	Aug	2009	LLA: Mat'l Contracts Awarded for D1021F Outage
18	Sep	2009	PTA: Work Package Assessments Complete for D1041S Outage
25	Sept	2009	DCP: Design Packages Approved & Issued for D1021F Outage
17	Oct	2009	ICA: Installation Contracts Awarded for D1021F Outage
28	Oct	2009	PTA: Work Package Assessments Complete for 2009 Online Packages
18	Dec	2009	AFS: 2009 Online Packages
26	Mar	2010	SOI: Start of Installation for D1041S Outage
26	Mar	2010	PTA: Work Package Assessments Complete for D1021F Outage
19	May	2010	AFS: D1041S Outage
01	Oct	2010	SOI: Start of Installation for D1021F Outage
24	Nov	2010	AFS: D1021F Outage
24	Jul	2011	PCM: Project Completion Milestone

A Project Execution Plan (PEP) will be approved by Dec 2007.

Attachment "D"

			CNSC Installation Completion Date															
			31-Dec-09	31-Dec-10	31-Dec-08	Complete	31-Dec-08	31-Dec-09	N/A	Complete	Complete	Complete	Complete	31-Dec-10	31-Dec-10	Complete	Complete	31-Dec-10
Outage	Outage Type	Unit	Norgren A/L Valves	Ion Chamber BIW Cable (RRS and SDS1)	Ion Chamber BIW Cable (SDS2)	[redacted]	Horiz. Flux Detector Tefzel Cable	Logansport Air Sequencing Valves Airlocks	Kopex Conduit Seals (All IPG)	[redacted]	[redacted]	[redacted]	[redacted]	Airlock Hoses & Norgren Addition	Limitorque Actuators	[redacted]	[redacted]	ITT Cannon Connector Replacement
D411 (Spring 2004)	Major	1																
D431 (Fall 2004)	Minor	3																
D521 (Spring 2005)	Major	2																
D541 (Fall 2005)	Minor	4		[redacted]														
D631 (Spring2006)	Major	3	[redacted]		[redacted]		[redacted]	[redacted]										
D611 (Fall 2006)	Minor	1	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]										
D741 (Spring 2007)	Major	4	[redacted]		[redacted]		[redacted]	[redacted]										
D721 (Fall 2007)	Major	2	I/P		X		X	I/P										
D811 (Spring 2008)	Major	1			X		X							X	X			X*
D901 (Spring 2009)	VBO	0																
D911 (Spring 2009)	VBO	1																
D921 (Spring 2009)	VBO	2																
D931 (Spring 2009)	Major	3	X[1]	X				X[1]						X	X			X*
D941 (Spring 2009)	VBO	4																
D1041 (Spring 2010)	Major	4												X	X			X*
D1021 (Fall 2010)	Major	2		X										X	X			X*

Non-Outage

	CNSC Installation Completion Date											
	31-Dec-09	Complete	31-Dec-07	31-Dec-07	Complete	31-Dec-07	31-Dec-10	31-Dec-10	Complete	Complete	Complete	31-Dec-10
	Gould Transmitters	[redacted]	Norgren Transfer Chamber Valves	Kepner Transfer Chamber Check Valves	[redacted]	Kopex Conduit Seals	Airlock Hoses & Norgren Addition	Limitorque Actuators	[redacted]	[redacted]	[redacted]	ITT Cannon Connector Replacement
0	X		X	X		X	X	X				
1			X	X		X	X	X				X*
2			X	X		X	X	X				X*
3			X	X		X	X	X				X*
4			X	X		X	X	X				X*

Notes:
Non-Outage items identified are non-unitized schedule. Date indicated is for completion of all station IPG work for the particular item.
C[2] - Airlock 2 Complete
X[1] - Airlock 1 moved to D931 by Outage Management
X[2] - Added by Charter Rev 2 to be committed to CNSC November 2007
C* - Removed from replacement program through exemption/QL extension
C** - Replacement is being completed every outage through regular PMs
I/P - In progress
Completion dates highlighted in yellow indicate schedule changes from CNSC submission.

REFERENCES

1. NK38-CORR-00531-13472, CNSC Letter from Senior Vice-President W. Robbins to Mr. G.R. Schwarz, Darlington NGS – 2006 Annual Update: Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 20, 2004

2. NK38-CORR-00531-12540, CNSC Letter from Senior Vice-President Gregory OD Smith to Mr. G. Schwarz, Darlington NGS – Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 30, 3004, dated November 30, 2004.

3. NK38-CORR-00531-12306, CNSC Letter from Senior Vice-President Gregory OD Smith to MS. B.A. Ecroyd, Safety Significance of Remaining Environmental Qualification (EQ) Issues Post June 30, 2004, dated May 31, 2004.

4. NK38-CORR-00531-12132, CNSC Letter from Senior Vice-President Gregory OD Smith to Mr. E. Leader, Progress in Addressing CNSC Environmental Qualification (EQ) Acceptance Criteria, dated December 18, 2003.

5. NK38-CORR-00531-13872, Action Item 20071314 CNSC Type I Inspection of Darlington NGS Environmental Qualification Program Conducted March 12 to March 30, 2007.

6. D-PCH-03651-10002-R002, EQ Closure and Component Replacements Project Charter.

7. D-BCS-03651-10003-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Partial Release Business Case Summary.

8. D-BCS-03651-10002-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Partial Release Business Case Summary.

9. D-BCS-03651-10001-R000, DND: EQ Closure and Component Replacement (Phase II) 16-38457, Developmental Release Business Case Summary.

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Business Case Summary

Probabilistic Risk Assessment Upgrade 10 - 62440 (OM&A)
Full Release Business Case Summary N - BCS - 03611 - 10000 - R0001

Name / Title / Phone	Location	Action	Signature	Date
M.Ruffolo Section Manager Probabilistic Safety Assessment Project	P72-3	Prepare BCS	PML for MR	4/4/12
P. Lawrence Manager, Design Projects Probabilistic Safety Assessment Project	P72-3	Review BCS	Paul Lawrence	4/4/12
F. Dermarkar Director Fukushima Project	P82-6	Review BCS	F. Dermarkar	4 Apr 2012
M. Elliot S.V.P. Nuclear Engineering and CNE	P82-5	Submit BCS		8 April 2012
R. Leavitt V.P. Nuclear Finance	P82-3	Review BCS	R Leavitt	April 16, 2012
W. Robbins Chief Nuclear Officer	P82-6	Review BCS		Apr 16/2012
D. Power V.P Corporate Planning and Asset Planning	TCH07G05	Review BCS		Apr 22/2012
D. Hanbidge S.V.P. and Chief Financial Officer	TCH19F27	Approve BCS		April 24/12
T. Mitchell President and Chief Executive Officer	TCH19A24	Approve BCS		24 April 12
		Choose an item.		
Click here to enter text.	Click here to enter text.	Return for Distribution		
Carolyn Sicard Nuclear Investment Management 702-4082	P82-3B6.2	Return for Distribution		

OFFICE OF THE PRESIDENT & CEO
APR 25 2012

1/ RECOMMENDATION:

We recommend a **Full** Release of an **additional $13.2** Million **OM&A**, including contingency of **$5048** Thousand, to execute contracts to complete the Darlington, Pickering B and Pickering A Probabilistic Risk Assessments (PRA).

Approval of this request will bring the total project cost to **$51.0** Million, including contingency. The current completion date for this project is 12/31/2014.

The Business Objectives of this **Regulatory** project are to:

- Upgrade the Darlington, Pickering A and Pickering B PRAs to the standard required by Canadian Nuclear Safety Commission (CNSC) Regulatory Standard S-294 "Probabilistic Safety Assessment (PSA) for Nuclear Power Plants". This is a requirement of each of the station's Power Reactor Operating Licences (PROL), with compliance dates of 12/31/2011 for Darlington, 12/31/2012 for Pickering B and 12/31/2013 for Pickering A.
- Update OPG's PRAs to comply with the requirements of N-PROG-RA-0016 "Risk and Reliability Program". This includes updating the PRAs to reflect the current station design and operating practices, demonstrating that OPG's facilities meet OPG's safety goals, and preparing tools to allow the interrogation of the PRAs.
- Develop sustainable in-house PRA expertise to allow future use of the PRAs to support technical, regulatory and business decisions.

The PRAs are also being used to support OPG's response to the accident at the Fukushima Nuclear Power Plant (NPP) and to support the Darlington Refurbishment Project. The schedule of the PRA project was changed to accommodate the schedule of the Darlington Refurbishment Project.

The total project estimate is based on actual costs incurred to upgrade the Darlington PRA, costs incurred to date and contract estimates for the Pickering B PRA, and bids received from major contractors on December 15, 2011 for the Pickering A PRA.

This release is the third and final release:

- The first partial release, approved in January 2009, was intended to initiate the upgrade to the Darlington PRA and to scope the PRA upgrades for Pickering B and Pickering A.
- The second partial release, approved in May 2010, was intended to complete the PRAs for Darlington and Pickering B, and to initiate the upgrade of the PRA for Pickering NGS A.
- This release is intended to complete the PRA for Pickering A.

This release includes a contingency of $2298 Thousand specific to the Pickering NGS A PRA. OPG will propose scope reductions for the Pickering NGS A PRA to strictly minimize costs while meeting the minimum requirements of OPG governance and the minimum regulatory requirements. The contingency is required in case the Project is not successful in satisfying the CNSC of the validity of the proposed scope reductions.

Since the May 2010 release, the scope of this project has increased:

- More detailed analysis was required to characterize the risk from seismic events and internal fires at Darlington NGS. The risks from these hazards were greater than originally expected.
- More detailed analysis will be required to characterize the risk from internal fires at both Pickering A and Pickering B. This reflects the experience gained in the Darlington fire PRA.
- Additional analysis of risk for shutdown units is required. Based upon experience at other Canadian utilities, this analysis was not originally thought to be required to meet CNSC Regulatory Standard S-294. However, additional analysis was required by the CNSC for Darlington and is expected to be required for Pickering.

Funds from all three releases are being used to support training of the project team staff and other OPG staff to allow future use of the PRAs to support technical, regulatory and business decisions.

OPG has already used PRAs to improve operational flexibility both in planned and unplanned situations. For example, at Darlington:

- Risk informed arguments were used to relax the test frequency of Shutdown Systems mandated by the PROL. This allowed Darlington to reduce its planned outage frequency from once every 2 years to once every 3 years.
- Risk informed arguments were used to relax the test frequency of check valves in the Emergency Coolant Injection System. This contributed to Darlington's efforts to shorten the duration of its planned outages.
- Risk informed arguments were used to support the reduction in scope of the Environmental Qualification Program. This supported significant reductions in maintenance effort at Darlington.
- Risk informed arguments were used to support continued operation of the Darlington units while unplanned repairs were performed to restore the integrity of its steam protected rooms. These arguments were used on two separate occasions; on the second occasion alone, the risk informed arguments helped prevent unplanned outages of approximately 120 unit days.

The Project has reduced costs by cost sharing the development of tools and methodology with other Canadian utilities, securing resources from the CANDU Owners Group to fund training, integrating the next routine update of the PRAs with the S-294 project, competitively sourcing PRA contracts, and simplifying the implementation processes for the Pickering A PRA based upon experience from the Pickering B PRA.

The Project is seeking to reduce the future costs of PRA maintenance by reducing the frequency of routine updates required by the CNSC from once every 3 years to once every 5 years.

$000's (incl contingency)	Type	LTD Dec 2010	2011	2012	2013	2014	2015	2016	Later	Total
Currently Released	Partial	21,391	14,171	1,772	523					37,857
Adj to Current Release	Adjustments	(4,057)	(3,068)							(7,125)
Requested Now	Full			8,373	11,509	454				20,336
Future Funding Req'd	None									-
Total Project Costs		17,334	11,103	10,145	12,032	454	-	-	-	51,068
Non Project Costs										-
Grand Total		17,334	11,103	10,145	12,032	454	-	-	-	51,068
Investment Type: Regulatory		Class: OM&A		NPV: (11,991)			IRR: N/A		Discounted Payback: N/A	

Submitted By: (Date)

April 8, 2012

Mark Elliot
S.V.P. Nuclear Engineering and Chief Nuclear Engineer

(OAR Element 1.1 Project in Budget)

Financial Approval By: (Date)

April 24/12

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

Line Approval By: (Date)

2012-04-26

Tom Mitchell
President and Chief Executive Officer

2/ BACKGROUND & ISSUES:

In April 2005, the Canadian Nuclear Safety Commission (CNSC) issued Regulatory Standard S-294 "Probabilistic Safety Assessments (PSA) for Nuclear Power Plants". S-294 requires each nuclear power plant licensee to complete a plant specific Level 2 PRA consistent with international standards. A PRA is a comprehensive and integrated assessment of the risk of the reactor. The PRA considers the frequency, progression and consequences of transient conditions to derive numerical risk estimates that provide a consistent measure of the risk of the reactor.

The Darlington, Pickering B and Pickering A Power Reactor Operating Licenses (PROL) all include requirements to prepare a PRA compliant with the requirements of S-294. The compliance dates are 31 December 2011 for Darlington, 31 December 2012 for Pickering B and 31 December 2013 for Pickering A.

N-PROG-RA-0016 "Risk and Reliability Program" also mandates the development, maintenance and use of PRAs at OPG Nuclear Generating Stations (NGS). PRAs are used to support plant configuration control, both at power and during outages, and in the review of planned design and operational changes. Industry experience suggests that the use of PRAs supports increased operational flexibility and reduces the frequency of unplanned unit outages, thereby reducing operating costs.

The Darlington PRA is also a key tool to support the Refurbishment Project. It has been used to support the environmental assessment, the Integrated Safety Review, and the assessment of safety improvement opportunities.

The Darlington and Pickering B PRAs have also been used to support OPG's response to the accident at the Fukushima NPP.

The purpose of this project is to complete Level 1 and Level 2 PRAs for all OPG NGSs. A Level 1 PRA identifies and quantifies the sequence of events that may lead to the loss of core structural integrity and massive fuel failures. A Level 2 PRA starts with the results of the Level 1 PRA, analyses containment behaviour, and quantifies the radio-nuclides released from the failed fuel to the environment.

This Project used as input the latest revisions of the PRAs that were available in 2009: a draft revision of the Darlington PRA that had been completed in 2003, the Pickering B PRA that had been revised in 2007 and a partial revision of the Pickering A PRA that had been completed in 2009. However, these PRAs had to be revised to reflect the current design and operating practices, to meet the requirements of S-294, and to prepare initial PRAs for fires, floods and seismic events.

The Project is managing costs by:

- Sharing the costs of developing tools and methodologies with other Canadian utilities. This amounts to approximately $1M is shared costs.
- Competitively bidding all elements of the project that were not underway by the end of 2008.
- Integrating the PRA project with the next triennial update of the PRAs required by N-PROG-RA-0016. (The latest partial revision of the Pickering A Level 1 at power PRA completed in 2009 cost approximately $400k.)
- Reducing the costs of the Pickering A PRAs by simplifying implementation processes and reducing scope. Savings may amount to between $1M and $2M.

PRAs have been used to improve operational flexibility both in planned and unplanned situations. For example, at Darlington:

- Risk informed arguments were used to relax the test frequency of Shutdown Systems mandated by the PROL. This allowed Darlington to reduce its planned outage frequency from once every 2 years to once every 3 years.
- Risk informed arguments were used to relax the test frequency of check valves in the Emergency Coolant Injection System. This contributed to Darlington's efforts to shorten the duration of its planned outages.
- Risk informed arguments were used to support the reduction in scope of the Environmental Qualification Program. This supported significant reductions in maintenance effort at Darlington.
- Risk informed arguments were used to support continued operation of the Darlington units while unplanned repairs were performed to restore the integrity of its steam protected rooms. These arguments were used on

two separate occasions; on the second occasion alone, the risk informed arguments helped prevent unplanned outages of approximately 120 unit days.

3/ ALTERNATIVES & 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							
Base OM&A							
Outage OM&A							
Project OM&A	0	(51,069)					
Total OM&A	0	(51,069)	0	0	0	0	0
Provision							
Capital							
Present Value (PV)	0						
Net Present Value (NPV)	N/A						
Internal Rate of Return (IRR) %	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Base Case: × *Not Recommended* - **Complete PRA Upgrades for Darlington and Pickering B, Do Not Upgrade the PRA for Pickering A**

Complete PRA upgrades for Darlington and Pickering B, but not Pickering A. The upgrade of the Pickering A PRA would be cancelled.

If this alternative is adopted, Pickering A will not be in compliance with S-294 by the date specified in its license handbook. This outcome would:

- Severely damage OPG's reputation with the CNSC and the public.
- Significantly reduce OPG's ability to respond to issues raised by the event at the Fukushima NPP. For example, the Level 2 PRA is an essential tool to evaluate the effectiveness of equipment and procedures designed to mitigate the consequences of a severe accident.

Therefore, it is not a recommended alternative. For the economic evaluation, the base case is assessed as having no cost going forward, the incremental costs and benefits of the alternatives are evaluated against it.

Alternative 1: ✓ *Recommended* - **Complete PRA Upgrades to Meet Licence Conditions for All OPG NGSs, Including Pickering A; Develop In-house PRA Expertise**

Complete PRA upgrades for Darlington, Pickering B and Pickering A to meet the dates specified in their respective licences. The Project has already upgraded the Darlington PRA and is on track under the current funding release to upgrade the Pickering B PRA by the end of 2012. Therefore, the incremental effort in this alternative is to upgrade the Pickering A PRA to bring it into compliance with Regulatory Standard S-294.

Completing the Pickering A PRA upgrade as planned through the current project organization is the most desirable alternative. The Project Team can leverage its experience with the Pickering B and Darlington PRAs to update the Pickering A PRA in the most efficient manner, to identify improvements in implementation processes, and to identify reductions in scope.

A total of $2298K of the PARA scope will be carried as contingency in case the Project is not successful in satisfying the CNSC of the validity of the proposed scope reductions.

Alternative 2: × *Not Recommended* - **Complete PRA Upgrades for Darlington and Pickering B, Reduce the Scope of the Pickering A PRA Upgrade**

Complete the PRA upgrades for Darlington and Pickering B, but limit the scope of the Pickering A PRA upgrade to Level 1 Full Power, Level 1 GSS and Level 2 Full Power. The Internal Fire, Internal Flood and Seismic PRAs would not be prepared. This Alternative would require CNSC acceptance; it is very unlikely that the CNSC will accept this reduced scope. Therefore, this alternative is not recommended.

4/ THE PROPOSAL

This release of the project will:

- Complete clean-up items for the Darlington Risk Assessment, e.g. response to CNSC questions on PRA deliverables.
- Complete the upgrade of the Pickering B Risk Assessment by December 31, 2012.
- Complete the upgrade of the Pickering A Risk Assessment by December 31, 2013.
- Continue the process of developing sustainable in-house PRA expertise through December 31, 2013.
- Enable project clean-up tasks to be completed in 2014.

The Project deliverables, and their status, are listed below by work program area.

1. **Prepare Tools and Methodologies and Conduct External Third Party Reviews and PRA Assessments that are Common to the OPG Fleet**

   The following tasks were completed under the January 2009 and May 2010 releases:

   - Level 1 Internal Events - Full Power Implementation 3rd Party Review.
   - Level 2 Internal Events – Full Power Methodology.
   - Level 2 Internal Events – Full Power Implementation 3rd Party Review.
   - Level 1 Internal Fire – Full Power Methodology.
   - Level 1 Internal Flood – Full Power Methodology.
   - Level 1 Seismic Event – Full Power Methodology.
   - External Events Screening Methodology – Full Power.

2. **Develop S-294 Compliant Probabilistic Risk Assessment for Darlington (DARA)**

   The following tasks were completed under the January 2009 and May 2010 releases:

   - DARA Level 1 Internal Events – Full Power.
   - DARA Level 1 Internal Events – Guaranteed Shutdown State (GSS).
   - DARA Level 2 Internal Events – Full Power.
   - DARA Level 2 Internal Events – Outage.
   - DARA Internal Fire PRA – Full Power.

- DARA Internal Flood PRA – Full Power.
- DARA Seismic PRA – Full Power.
- DARA Internal Fire PRA – Outage.
- DARA Internal Flood PRA – Outage.
- DARA Seismic Event PRA – Outage.
- DARA Screening Analysis for Low Frequency Events – Full Power.
- DARA Screening Analysis for Low Frequency Events – Outage.

3. Develop S-294 Compliant Probabilistic Risk Assessment for Pickering B (PBRA)

The following tasks were either completed under the January 2009 release or will be completed under the May 2010 release:

- PBRA S-294 Gap Assessment.
- PBRA Level 1 Internal Events – Full Power.
- PBRA Level 1 Internal Events – Guaranteed Shutdown State (GSS).
- PBRA Level 2 Internal Events – Full Power.
- PBRA Level 2 Internal Events – Outage.
- PBRA Internal Fire PRA – Full Power.
- PBRA Internal Flood PRA – Full Power.
- PBRA Seismic PRA – Full Power.
- PBRA Internal Fire PRA – Outage.
- PBRA Internal Flood PRA – Outage.
- PBRA Seismic PRA – Outage.
- PBRA Screening Analysis for Low Frequency Events – Full Power.
- PBRA Screening Analysis for Low Frequency Events – Outage.

4. Develop S-294 Compliant Probabilistic Safety Assessment for Pickering A (PARA)

The following tasks were completed under May 2010 release:

- PARA S-294 Gap Assessment.
- PARA Screening Analysis for Low Frequency Events – Full Power.
- PARA Screening Analysis for Low Frequency Events – Outage.

The following tasks will be completed under this release:

- PARA Level 1 Internal Events - At Power.
- PARA Level 1 Internal Events – Outage.
- PARA Level 2 Internal Events – Full Power.

- PARA Level 2 Internal Events – Outage.
- PARA Internal Fire PRA – Full Power.
- PARA Internal Flood PRA – Full Power.
- PARA Seismic PRA – Full Power.
- PARA Internal Fire PRA – Outage.
- PARA Internal Flood PRA – Outage.
- PARA Seismic PRA – Outage.

5. Develop Sustainable Internal Expertise for Probabilistic Risk Assessment

Develop sustainable internal probabilistic risk 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 staff (~6 FTEs) will be trained (classroom and on the job) by the Project and then transitioned to a centralized PRA organization to provide the above support. The transition will occur in mid to late 2013 as the Pickering A PRA moves to a conclusion. The central organization will be OM&A Base funded and is in the current Business Plan.

Overall Project Objectives

The project will meet the following overall requirements:

1. A formal quality assurance process for completing PRAs will be established and applied.
2. PRA models will reflect the plant as built and operated as closely as reasonably achievable within limitations of PRA technology and consistent with risk impact.
   - Both internal and external events will be included.
   - Full Power and Shutdown (GSS) modes will be included.
   - Sensitivity analysis, uncertainty analysis and importance measures will be included.
3. PRA models will be developed using assumptions and data that are realistic and practical.
4. The level of detail of the PRAs will be consistent with plant testing and configuration management programs.
5. CNSC acceptance of the methodology and computer codes used for the PRA will be obtained.

The project estimate is based on actual costs for the Darlington PRA, actual costs and contract estimates for the Pickering B PRA, and fixed-price bids received on December 15, 2011, for the Pickering A PRA upgrade.

The estimate also includes the costs to establish corporate oversight, create a dedicated PRA project team to manage and execute the project, provide expert and station review of vendor product, provide regular interface with the regulator and develop a sustaining in house PRA capability.

5/ QUALITATIVE FACTORS

PRA has proven to be an important tool in the safety assessment of nuclear reactors throughout the world. Decision making, with regards to many nuclear safety issues, has been facilitated by both general insights from and direct application of this technology. The existing PRAs at OPG have already been used to improve public safety, as discussed in examples below, and the upgrades are expected to improve upon their effectiveness and performance, while meeting plant license requirements.

- PBRA was used to support the Integrated Safety Review (ISR) and the Environmental Assessment (EA) for the Pickering B Refurbishment study.
- DARA is an important tool in preparation of the ISR and EA for the Darlington Refurbishment Program going forward.
- PARA was used to identify improvements and support restart following Unit 1 and Unit 4 return to service.
- 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.

The Darlington PRA is being used to support the Refurbishment Project. The Darlington and Pickering PRAs are being used to support OPG's response to the accident at the Fukushima NPP.

The continued use of the PRA in a Risk Informed Decision Making (RIDM) regulatory environment is highly dependent on its quality and capability. A PRA that is S-294 complaint is recognized by the industry to be of high quality and capability. It is essential that future risk informed decisions are to be supported by S-294 compliant PRAs if they are to be accepted by the regulator.

6/ RISKS ANALYSIS (See Attachment D for details)

Low 1 to 3	Medium 4 to 9	High 10 to 25

Probability \ Impact	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	Mitigation	Specific Cont'ncy $000's	Probability X Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environmental	Nuclear Safety	Risk Rating (1 to 25)
The CNSC may not accept one or more of the methodologies for completing the project work, leading to schedule delays and rework of proposed methodologies.	▪ OPG hired contractors with extensive industry experience. ▪ OPG engaged industry partners and US-based experts to develop methodologies. ▪ Methodologies for Internal Fire, Internal Flood and Seismic Event PRAs based on industry standards approved by the US NRC. ▪ 3rd party industry expert review of all methodologies. ▪ Regular communication with the CNSC to keep them abreast of project progress.	Before		5	25	25		10				25
		After		2	4	6		2				6
The project may not complete one or more of the work activities on time to meet compliance dates listed in the PROLs, leading to negative impacts to OPG's corporate reputation.	▪ Resource-loaded schedule maintained by the project. ▪ Weekly reviews of project schedule with contractors. ▪ Ongoing identification of schedule risks and development of response plans with contractors. ▪ PARA RFP includes provisions to ensure contractor reports schedule issues/ risks to the project in a timely matter.	Before		15	20		20					20
		After		6	8		8					10
Analysis reveals situations that require shutdown of one or more units	DIRP and TOE processes will be used to address issues identified during analysis.	Before		15	15		15	12				15
		After		9	9		9	8				9

The scope of PBRA or PARA may need to be expanded to resolve technical issues discovered, resulting in additional project costs and schedule delays.	▪ Close communication with vendor to identify and resolve technical issues early. ▪ Ongoing discussion with vendor to ensure need for additional scope is identified immediately and addressed. ▪ Communication with OPG Nuclear Senior Management to obtain approvals to add resources or release contingency if required.	Before		15	15							15
		After		9	9							9
The PRAs may identify the need for plant upgrades, which could lead to large costs to OPG.	▪ Discovery Issue Resolution and Technical Operability Evaluation processes will be used to address issues identified during analysis. ▪ Analysis will be used to support risk-informed decisions with plant modifications. ▪ Proposed modifications/ upgrades will be assessed by the AISC process.	Before		15	15		3	2				15
		After		9	9		2	2				9
The selected vendor may not have the required knowledge and expertise with CANDU stations to complete PARA to OPG's quality expectations, leading to the need for additional project resources.	▪ Project is using a rigorous RFP process with prequalified bidders. ▪ Extensive review of the technical aspects of the bids and previous experience of the bidders will be conducted.	Before		6	6							6
		After		2	2							2
OPG's internal resources may not be sufficient to complete the project scope on time, resulting in schedule delays or the need for additional personnel.	▪ Project and business planning to ensure resources are available. ▪ Project to engage station resources early in the planning phases. ▪ OPG engaged the services of former Shift Managers and other Subject Matter Experts to assist in information transfer between the project team and vendors.	Before		10	10	10						10
		After		2	2	2						2

Detailed Level 2 analysis may be required for Outage, Internal Fire, Internal Flood and Seismic PRAs. (The current scope of the Project assumes that only limited scope analyses in these areas.)	▪ Start work as soon as practically possible to provide enough time to complete Level 2 analysis prior to PROL required date. ▪ Reduced scope analyses were accepted by the CNSC for Darlington. Leverage this analysis to minimize the likelihood of additional analysis for Pickering. ▪ Keep close communication with vendor to identify potential need for Phase 2 ASAP. ▪ Increase frequency of communication with OPG Nuclear Senior Management to expedite approvals of contingency release.	Before		8	10							10
		After		4	5							5
Phase 2 analysis may be required for Internal Fire, Internal Flood and Seismic PRAs. (The fire, flood and seismic PRAs are being completed in a phased approach. Phase 2 is a more detailed analysis and is only required if the simplified bounding Phase 1 cannot meet the Project's goals.)	▪ Start Phase 1 work as soon as practically possible to provide enough time to complete Phase 2 analysis prior to PROL date. ▪ Keep close communication with vendor to identify potential need for Phase 2 ASAP. ▪ Optimize Phase 1 scope once Phase 2 is known to be required. ▪ Increase frequency of communication with OPG Nuclear Senior Management to expedite approvals of contingency release.	Before		8	20							20
		After		4	8							8

Detailed outage PRAs may be required for Internal Fire, Internal Flood and Seismic PRAs. (The current scope of the Project assumes that only limited scope analyses in these areas.)	▪ Start work as soon as practically possible to provide enough time to complete Outage analysis prior to PROL required date. ▪ Reduced scope analyses were accepted by the CNSC for Darlington. Leverage this analysis to minimize the likelihood of additional analysis for Pickering. ▪ Keep close communication with vendor to identify potential need for Phase 2 ASAP. ▪ Increase frequency of communication with OPG Nuclear Senior Management to expedite approvals of contingency release.	Before		9	9							9
		After		3	3							3

7/ POST IMPLEMENTATION REVIEW

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date	PIR Responsibility (Sponsor Title)
Simplified	28-Jun-13	30-Jun-14	Director, Engineering Services Division

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure Person / Group?
1.	Methodologies	OPG PRA methodologies are consistent with standard industry practice and accepted by the CNSC as per S-294.	All OPG PRA methodologies are accepted by the CNSC.	All OPG PRA methodologies are accepted by the CNSC	PIR Team
2.	Staff Development	No OPG employees are qualified in all aspects of modern PRA methodologies. The target is ~60% complete. The most significant gap is in the Level 1 GSS, Level 2 Full Power and Fire elements. The remainder of the project will focus on closing these gaps.	Six (6) OPG employees to be qualified in all aspects of modern PRA methodologies	1) Development of OPG PRA qualification that is aligned with all aspects of modern methodologies 2) All six employees become qualified	PIR Team
3.	Darlington Risk Assessment (DARA)	The DARA has been accepted by Station Engineering and the Refurb Project. The CNSC has deemed the DARA methodologies to be complaint with S-294.	Scope and quality of OPG's PRAs to be consistent with standard industry practice and S-294. They can be used to support Risk Informed Decision Making.	1) Each is compliant with their respective PROL 2) Each is accepted for use by the respective Director, Station Engineering. 3) DARA is accepted for use by the Refurb Project.	PIR Team
4.	Pickering B Risk Assessment (PBRA)	The upgrade of the PBRA is 75% and will achieve the target result under the current release.			
5.	Pickering A Risk Assessment (PARA)	Scope and quality not consistent with S-294 or standard industry practice.			

A Lessons Learned Report (N-TMP-10204) will also be prepared at the end of the project.

The following are required for Final Project Close Out:

- Project Closure Report (FIN-FORM-PA-005).
- Post Implementation Review (PIR), 1 year after completion of PARA (FIN-PROC-PA-012).
- Senior Management Review of PIR.

APPENDIX "A' GLOSSARY (acronyms, codes, technical terms)

CNSC: Canadian Nuclear Safety Commission

DARA: Darlington A Risk Assessment

Level 1 PRA: Probabilistic Safety Assessment of Core Damage Frequency

Level 2 PRA: Probabilistic Safety Assessment of Large Release Frequency

PARA: Pickering A Risk Assessment

PBRA: Pickering B Risk Assessment

PRA: Probabilistic Risk Assessment

PSA: Probabilistic Safety Assessment

PROL: Power Reactor Operating License

RIDM: Risk Informed Decision Making

S-294: CNSC Regulatory Standard "Probabilistic Safety Assessment (PSA) for Nuclear Power Plants"

APPENDIX "B" Comparison of Total Project Estimates

This Appendix compares the Total Project Estimate for each BCS

Total Project Estimate (by Year incl Contingency)

BCS Type	Class	Mth	Yr	2008	2009	2010	2011	2012	2013	2014	Later	Total Project Est
Partial	OM&A	Jan	2009	1,800	10,200	10,400	4,400					26,800
Partial	OM&A	May	2010		6,121	15,270	14,171	8,216	2,243			46,021
Full	OM&A	May	2012		6,121	11,213	11,103	10,145	12,032	454		51,068
												0
												0
												0
LTD Spent	OM&A	Dec	2011		6,125	11,208	11,105					28,438

Comments:

Since the May 2010 release, the scope of this project has increased for all three stations:

- Additional analysis is required to better characterize the risk from seismic events and internal fires. Experience with the Darlington PRA has indicated that the risks from these hazards are greater than originally expected.
- Additional analysis of risk for shutdown units is required. This analysis was not originally thought to be required to meet CNSC Regulatory Standard S-294.

APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

Financial Assumptions:

Discount Rate:	7%	Cost Escalation (Yr)	2%	SR&D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Depreciation Rate (Capital)	N/A	PST	No	Interest Rate (Capital)	OM&A N/A
Revenue Rate	N/A	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete:	Zero to Minimal	Fixed Price Contract	Yes	3rd Party Estimate	No
Quality of Estimate	Release +15% to -10%	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	No	Budgetary Quote	Yes	First Unit Actual Used	Yes
Firm Vendor Proposal	Yes	Cost Sharing	No	Competitive Bid	Yes
Reviewed by Sponsor	Yes	Fee for Service	No	Contracts in place	Yes

Comments:

Rationale for Capital Cost Classification:

Not applicable

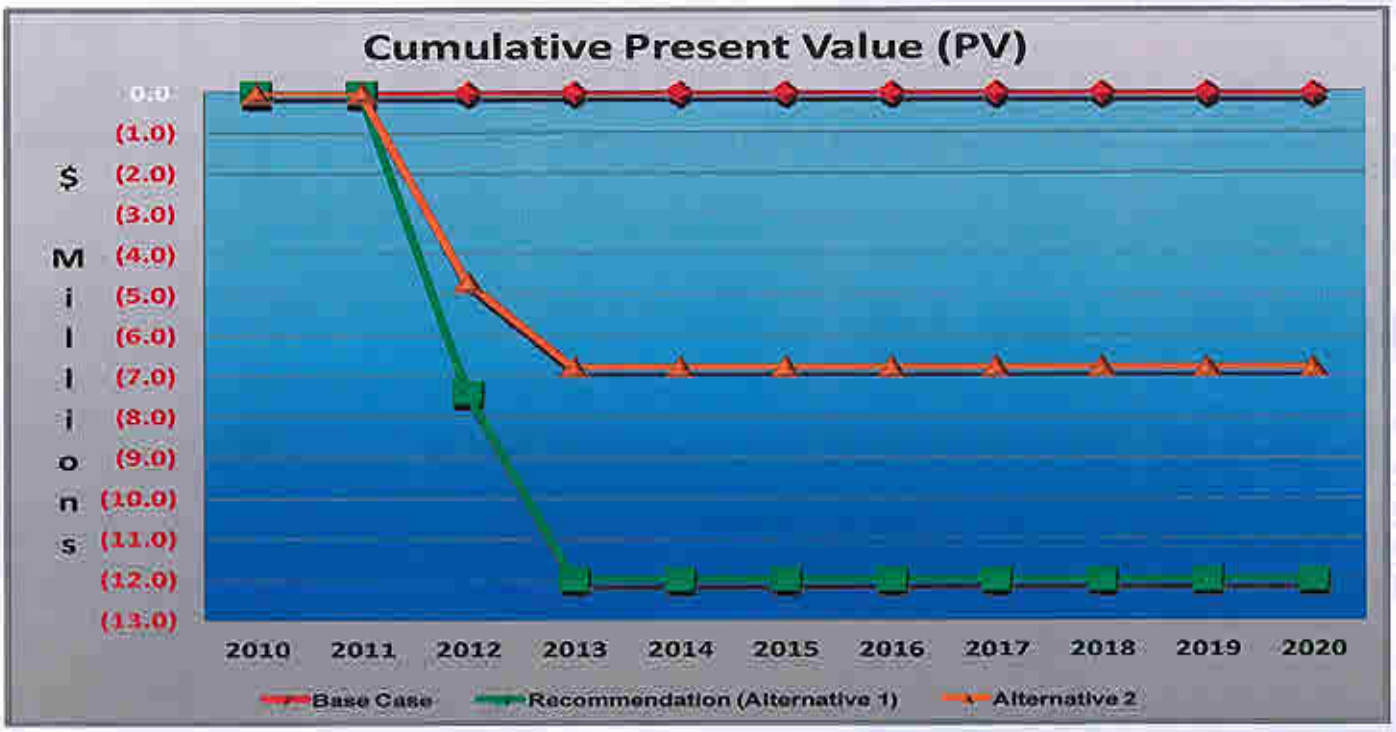
Generation Plan Assumptions:

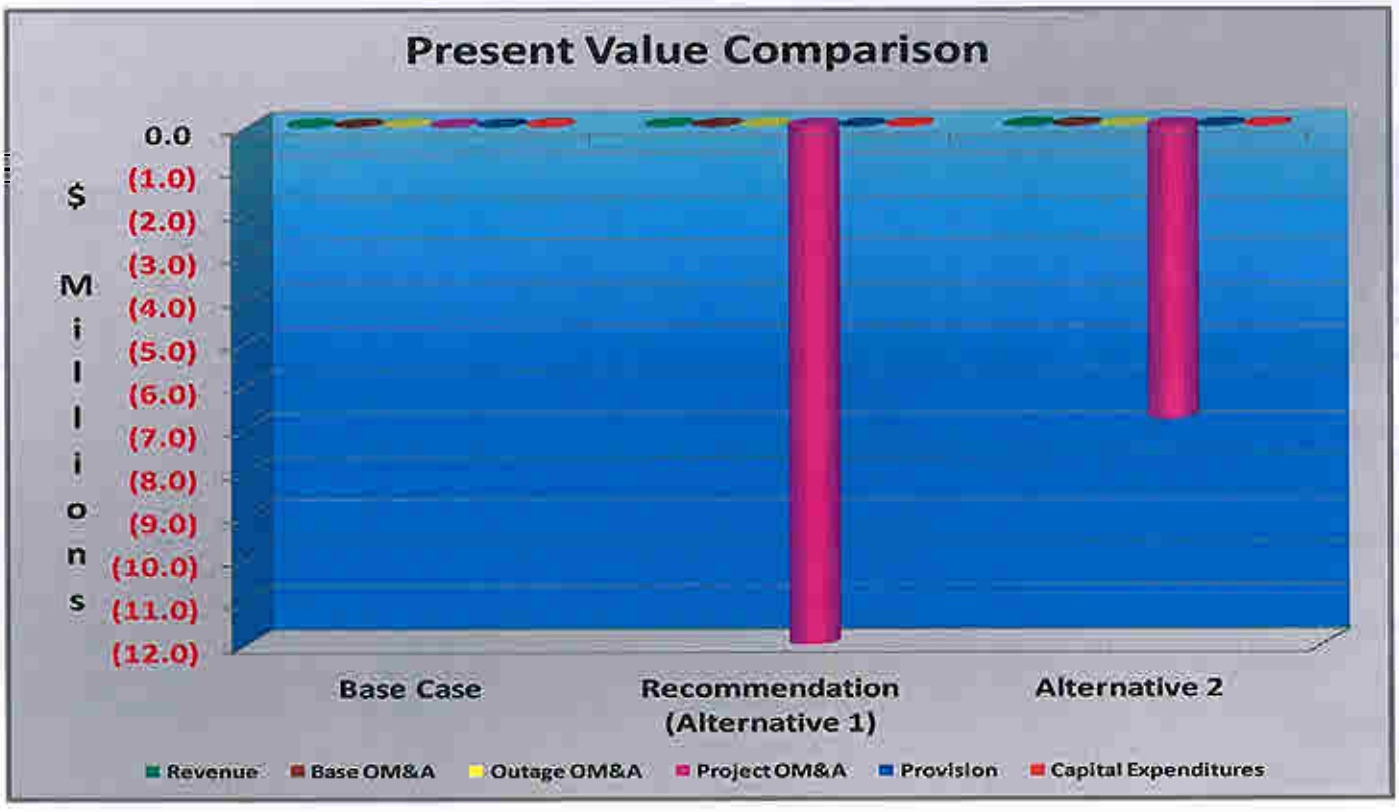
Station	Unit	EOL or Refurb	MW	Planned Outages for Project Work						
Pickering A	1	Jun-20	515	N/A						
	4	Jun-20	515	N/A						
Pickering B	5	Nov-18	516	N/A						
	6	Nov-18	516	N/A						
	7	Jun-20	516	N/A						
	8	Jun-20	516	N/A						
Darlington	1	Sep-16	878	N/A						
	2	Feb-18	878	N/A						
	3	Sep-19	878	N/A						
	4	Jan-21	878	N/A						

Comments:

APPENDIX "D"

FINANCIAL MODEL – ASSUMPTIONS
Impact on Operations





APPENDIX "E" PROJECT DELIVERABLES

Release Deliverable	Description	Item	Cost ($000's)
Project Management/ Common	Project controls, reporting, training, expenses, risk management, contractor management, etc.		8,122
Full DARA	All Elements		17,579
DARA Technical Review	Technical reviews of completed Darlington PRAs.		2,629
PBRA Level 1 Internal Events - At Power	PBRA - Internal events leading to fuel damage while units at power.		1,804
PBRA Level 1 Internal Events - Outage	PBRA - Internal events leading to fuel damage while units in outage.		1,415
PBRA Level 2 Internal Events - Full Power	PBRA - Internal events leading to environmental release while units at power.		1,945
PBRA Level 1 Internal Fire - Full Power	PBRA - Internal fire leading to fuel damage while units at power.		863
PBRA Level 1 Internal Flood - Full Power	PBRA - Internal flood leading to fuel damage while units at power.		427
PBRA Level 1 Seismic Event - Full Power	PBRA - Seismic event leading to fuel damage while units at power.		501
PBRA - Technical Reviews	Technical reviews of completed Pickering B PRAs.		1,276
PARA Level 1 Internal Events - At Power	PARA - Internal events leading to fuel damage while units at power.		2,052
PARA Level 1 Internal Events - Outage	PARA - Internal events leading to fuel damage while units in outage.		1,796
PARA Level 2 Internal Events - Full Power	PARA - Internal events leading to environmental release while units at power.		1,970
PARA Internal Fire - Full Power	PARA - Internal fire leading to fuel damage while units at power.		960
PARA Internal Flood - Full Power	PARA - Internal flood leading to fuel damage while units at power.		559
PARA Seismic Event - Full Power	PARA - Seismic event leading to fuel damage while units at power.		659
PARA - Technical Reviews	Technical reviews of completed Pickering A PRAs.		1,464
Contingency	Project contingency		5,048
Total			51,069

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Business Case Summary

Probabilistic Risk Assessment Upgrade 10 - 62440 (OM&A)
Full Release Business Case Summary N - BCS - 03611 - 10000 - R0001

ATTACHMENT "A" PROJECT COST SUMMARY

Accounting Basis										
Project Management	4,403	1,878	1,941							8,122
DARA	20,128	66								20,194
PBRA	3,845	4,286	128							8,231
PARA	67	2,858	6,281	454						9,460
										-
										-
										-
Interest (Capital Project)										-
Project Costs	28,438	8,879	8,250	454	-	-	-	-		46,021
General Contingency										-
Specific Contingency		1,266	3,782							5,048
Project Costs	28,438	10,145	12,032	454	-	-	-	-		51,069

Funding Basis											
Current Release	Project Costs	31,071	1,772	523							33,366
	Contingency	4,491	-	-							4,491
	Total	35,562	1,772	523	-	-	-	-	-		37,857
Adj to Current Release	Project Costs	(2,633)	-	-							(2,633)
	Contingency	(4,491)	-	-							(4,491)
	Total	(7,124)	-	-	-	-	-	-	-		(7,124)
This Release	Project Costs	-	7,107	7,727	454						15,288
	Contingency		1,266	3,782	-						5,048
	Total	-	8,373	11,509	454	-	-	-	-		20,336
TTO Released	Project Costs	28,438	8,879	8,250	454	-	-	-	-		46,021
	Contingency	-	1,266	3,782	-	-	-	-	-		5,048
	Total	28,438	10,145	12,032	454	-	-	-	-		51,069
Future Releases	Project Costs										-
	Contingency										-
	Total	-	-	-	-	-	-	-	-		-
Project Funding		28,438	8,879	8,250	454	-	-	-	-		46,021
Contingency Funding		-	1,266	3,782	-	-	-	-	-		5,048
Total Funding		28,438	10,145	12,032	454	-	-	-	-		51,069

Budget										
2011 - 2015 Business Plan	17,334	11,752	8,870	1,996						39,971
Variance to Budget	(11,104)	2,393	620	1,542	0	0	0	0		(6,550)

Other										
Removal Costs (above)										-
Inventory W / O										-
Spare Parts in Invent										-

Reviewed by: 4/4/2012 (Date)
Mike Ruffolo
Project Manager

Approved by: 4/4/12 (Date)
Paul Lawrence
Strat IV Manager

ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

	$ 000's OM&A	LTD Dec 2011	Total Project Last BCS May 2010	Total Project This BCS May 2011	Variance	Comments
Scores Basis	Project Management	3,501	5,562	7,166	1,604	Additional Cost/ Schedule Analyst and oversight support required to manage the increased scope and keep project on track.
	Common	902	1,222	956	(266)	
	DARA	20,123	14,763	20,208	5,445	Additional costs associated with extending Fire and Seismic PRA from Phase 1 to Phase 2, and Flood PRA from Phase 1 to Phase 1A. Corresponding increases were also necessary for Technical Reviews, as well as for augmenting PRA department capabilities in specialty areas, such as for the review of building seismic response modeling and for operational input (e.g. ANO & CRSS) to determine possible operational responses to beyond-design-basis (BDB) accidents.
	PBRA	3,845	9,340	8,231	(1,109)	
	PARA	67	7,108	9,460	2,352	The planned lower costs under the PBRA were not realized during PARA RFP process. This estimate is lower than the proposed costs received in the RFP (see note in contingency line item).
					-	
					-	
					-	
					-	
	Interest (Capital Project Only)				-	
	Project Costs (Scores Basis)	**28,438**	**37,995**	**46,021**	**8,026**	
	General Contingency				-	
	Specific Contingency		8,026	5,048	(2,978)	Although the Project is mature and the costs are better known, significant contingency is still required in support of PARA. The Project will attempt to reduce the scope of the PARA while still meeting the project objectives. The result is that $2298K of the PARA scope will be carried as contingency in case the Project is not successful in satisfying Stakeholders (e.g., station and CNSC).
	Project Costs (Scores Basis)	**-**	**46,021**	**51,069**	**5,048**	

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

Comments:

As explained above, the scope of the Darlington PRA has expanded significantly since the previous release. The main impact of this scope increase has been to the schedules of the Pickering B and A PRAs. Some work that was planned to be completed in 2010 and 2011 for the Pickering B PRA specifically, has now been delayed to 2012 and 2013, and therefore included in the scope of this release.

ATTACHMENT "C" SCHEDULE

Key Milestones

Completion Date	Description – January 2009 Release
7-Mar-10	DARA – Level 2 Internal Events – Full Power (Purchase Order Issued)
21-Mar-10	DARA – Level 1 Internal Events – GSS (Purchase Order Issued)
25-Mar-10	Level 1 Full Power Seismic Methodology (Accepted by OPG)
29-Mar-10	Level 1 Full Power Internal Flood Methodology (Accepted by OPG)
31-Mar-10	Level 1 Full Power Internal Fire Methodology (Accepted by OPG)
26-Apr-10	External Events Screening Analysis (Purchase Order Issued)
21-May-10	Level 2 Internal Events – Full Power Methodology (Accepted by OPG)
25-Jun-10	PBRA – Level 1 Internal Events – Full Power (Purchase Order Issued)
16-Jul-10	External Events Screening Analysis Methodology (Accepted by OPG)
5-Aug-10	DARA – Level 1 Internal Events – Full Power (FDC 1 & 2 Analysis Complete)
19-Aug-10	DARA – Level 1 Internal Fire Phase 1 (Final Report Accepted by OPG)
19-Aug-10	DARA – Level 1 Internal Flood Phase 1 (Final Report Accepted by OPG)
11-Sep-10	DARA – Level 1 Seismic Phase 1 (Final Report Accepted by OPG)
15-Sep-10	DARA – Level 1 Internal Events – Full Power (FDC 1 through 9 Analysis Complete)
8-Oct-10	Level 1 Internal Events – GSS Methodology (Accepted by OPG)
Completion Date	**Description – May 2010 Release**
2-Nov-2010	PBRA – Level 1 Internal Events – GSS (Purchase Order Issued)
23-Jan-2012	External Events Screening Analysis (Final Report Accepted by OPG)
25-Feb-2011	PBRA – Level 2 Internal Events – Full Power (Purchase Order Issued)
14-Jul-2011	PBRA – Level 1 Internal Fire Phase 1 (Purchase Order Issued)
27-Jun-2011	PBRA – Level 1 Internal Flood Phase 1 (Purchase Order Issued)
27-Jun-2011	PBRA – Level 1 Seismic Phase 1 (Purchase Order Issued)
8-Jun-2011	DARA – Level 2 Internal Events – Full Power (EPRC Results Complete)
26-Nov-2010	DARA – Level 1 Internal Events – Full Power (Final Report Accepted by OPG)
10-Jun-2011	DARA – Level 1 Internal Events – GSS (Final Report Accepted by OPG)
25-Aug-2011	DARA – Level 2 Internal Events – Full Power (Final Report Accepted by OPG)
2-Aug-2012	PBRA – Level 1 Internal Events – Full Power (Final Report Accepted by OPG)
7-Mar-2012	PARA – Level 1 Internal Events – Full Power (Purchase Order Issued)
22-Mar-2012	PARA – Level 1 Internal Events – GSS (Purchase Order Issued)
22-Mar-2012	PBRA – Level 1 Internal Fire Phase 1 (Final Report Accepted by OPG)
10-May-2012	PBRA – Level 1 Internal Flood Phase 1 (Final Report Accepted by OPG)
21-Jun-2012	PBRA – Level 1 Seismic Phase 1 (Final Report Accepted by OPG)
23-Nov-2012	PBRA – Level 1 Internal Events – GSS (Final Report Accepted by OPG)
22-Nov-2012	PBRA – Level 2 Internal Events – Full Power (Final Report Accepted by OPG)
Completion Date	**Description – This Release**
22-Mar-2012	PARA – Level 2 Internal Events – Full Power (Purchase Order Issued)
22-Mar-2012	PARA – Level 1 Internal Fire Phase 1 (Purchase Order Issued)
22-Mar-2012	PARA – Level 1 Internal Flood Phase 1 (Purchase Order Issued)
22-Mar-2012	PARA – Level 1 Seismic Phase 1 (Purchase Order Issued)

TBD	PARA – Level 1 Internal Events – Full Power (Final Report Accepted by OPG)
TBD	PARA – Level 1 Internal Fire Phase 1 (Final Report Accepted by OPG)
TBD	PARA – Level 1 Internal Flood Phase 1 (Final Report Accepted by OPG)
TBD	PARA – Level 1 Seismic Phase 1 (Final Report Accepted by OPG)
TBD	PARA – Level 1 Internal Events – GSS (Final Report Accepted by OPG)
TBD	PARA – Level 2 Internal Events – Full Power (Final Report Accepted by OPG)

A Project Execution Plan (PEP) was approved on 1-Apr-10. The project conducted a review and update of the PEP as part of the BCS preparation process.

In Service Declarations: (Capital only)

Date	Description	$000's (Total = Project Cost incl cont'g)	% In Service (= 100%)
	Not applicable		

Comments:

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Business Case Summary

Probabilistic Risk Assessment Upgrade 10 - 62440 (OM&A)
Full Release Business Case Summary N - BCS - 03611 - 10000 - R0001

Attachment "D" Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 100	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 month	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 > $15MCat. 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 ORMajor 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 OrderCat. 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 finesORPotential 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 spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger 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 scheduleORPossibility 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 - reportableAdministrative infractionsPublic 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 qualityRoutine non-conformance, can be easily dispositioned	Complaints from local public	Isolated non-complianceORRoutine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker	Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God	

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Business Case Summary

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

Name / Title / Phone	Location	Action	Signature	Date
S. Thurston Project Engineer x701-5495	P72-2	Prepare BCS		Oct. 26, 2010
A. Maxim Project Leader x701-3579	P72-1	Review BCS		2010/10/26
E.H. Wong Project Manager x701-4173	P72-2	Review BCS		2010/10/26
J.Taras Section Manager, Process Scheduling x701-3755	P72-1	Review BCS		2010/10/26
N. Rahman Manager, Design Projects - Pickering A x701-4053	P72-1	Review BCS		26 OCT 2010
Ron Ball Sr Advisor, Finance x702 4084	P82-3B6	Review BCS		27 Oct 10
Dwight Zerkee Manager, Investment Management x702-5058	P82-3A6	Review BCS		27 Oct 10
Sorin Marinescu Manager, Components & Equipment - PB x701-4264	P41	Review BCS		2010/11/01
Mike Peckham Vice President, Projects & Modifications x701-6063	P72-1	Review BCS		2010/NOV 8
Stephen Rogers Director, Asset Planning & Integration x400-3993	TCH07E5	Review BCS	M. Stephen Rogers	2010/Nov 30
Carolyn Sicard Nuclear Investment Management 702-4082	P82-3B6.2	Return for Distribution		

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Business Case Summary

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

Name / Title / Phone	Location	Action	Signature	Date
Jamie Lawrie Director, Nuclear Investment Management x702-5086	P82-3	Review BCS		Nov. 5/2010
Keith Howard Director, Station Engineering – Pickering B x701-4342	P41	Review BCS		11-NOV-2010
Paul Pasquet Senior Vice President, Pickering B x701-2922	P41	Submit BCS		Nov 11, 10
Randy Leavitt VP, Nuclear Finance x702-5177	P82-3	Review BCS		Nov. 15, 2010
Don Power VP, Corporate Investment Planning x400-7172	TCH07G05	Review BCS		Nov 7, 2010
Wayne Robbins Chief Nuclear Officer x702-5294	P82	Review BCS		2010-11-23
Donn Hanbidge SVP & Chief Financial Officer x400-2395	TCH19F27	Approve BCS		Dec 8/2010
Tom Mitchell President & CEO x400-2121	TCH19A24	Approve BCS		Dec 12 2010
Sue MacKinnon Nuclear Investment Management 702-4082	P82-3B6.2	Return for Distribution		

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Business Case Summary

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

1/ RECOMMENDATION:

We recommend a Superseding Release of an additional $18.9 Million OM&A (including $3.6M contingency) to complete the installation of new divider plate locking tab devices on the remaining 4 steam generators in Unit 8 and 6 steam generators in Unit 7 and project closeout. Approval of this request will bring the total to-date funding to $39.4 Million including contingency.

The business objective stated in the 2007 Full Release BCS is to remove the current requirement to shut down Unit 7 and Unit 8 after 6.3 Effective Full Power Years (EFPY) of locking tab operation (currently February 2012 for Unit 8 and September 2012 for Unit 7) because of the threat of fatigue failure of the cold leg locking tabs, by developing and installing a new design that will:

- Allow Units 7 and 8 to run until unit End of Life (currently in 2020) without concerns of locking tab failure.
- Reduce the overall project cost and dose uptake by ~$4.3M and 40% respectively (compared to Units 5 & 6)
- Align with the Pickering B 85/5 initiative by allowing installation within a 40 day outage schedule.
- Allow inspection/maintenance to be conducted with minimal interference with the new design.
- Allow for the removal and/or replacement of components of the new design with relative ease, if required.

The project was fully released in March 2007 and was estimated at $20.5M based on completion of the conceptual design. The original schedule called for completion of Unit 7 and Unit 8 by the end of 2010 however to-date, locking tabs have been installed on only 6 steam generators in Unit 7 and 8 steam generators in Unit 8 with the remaining installations scheduled for 2012 which is just within the 6.3 EFPY timeline.
Major cost variances that have resulted in the request for additional funding are attributed to:

- Underestimation of Project execution costs ($4.8M)
- Remobilization costs to accommodate the remaining schedule ($4M)
- Radiological Discovery Issues (eg. Hot particles & D2O leaking) ($2.8M)
- Costs to develop contingency tooling and installation quality issues ($2.7M)
- A change in accounting practice (addition of SAVH and Project Support charges, adoption of International Financial Reporting Standards in Canada) ($1M)
- Loss of skilled trades due to Alpha radiation exposure external to OPG (costs incorporated into bullets 2 and 4 above)

Comprehensive lessons learned evaluations have been completed and findings have been incorporated into the project to address all major known issues. We are confident that we have a credible schedule and cost estimate to complete the project.

$000's (incl contingency)	Type	LTD 2009	2010	2011	2012	2013	2014	2015	Later	Total
Currently Released	Full	8,617	11,908	-						**20,525**
Requested Now	Superseding		622	817	17,128	301				**18,868**
Future Funding Req'd	None									**-**
Total Project Costs		**8,617**	**12,530**	**817**	**17,128**	**301**	**-**	**-**	**-**	**39,393**
Non Project Costs										**-**
Grand Total		**8,617**	**12,530**	**817**	**17,128**	**301**	**-**	**-**	**-**	**39,393**
Investment Type		**Class**		**NPV**			**IRR**		**Discounted Payback**	
Sustaining		**OM&A**		**(12,115)**			**N/A**		**N/A**	

Submitted By: (Date)

Nov 11, 2010

Paul Pasquet
Senior VP, Pickering B

Financial Approval By: (Date)

Dec 9, 2010

Donn W. Hanbidge
Chief Financial Officer

(OAR Element 1.4 Variance)
Line Approval By: (Date)

Dec 12, 2010

Tom Mitchell
President & CEO

2/ BACKGROUND & ISSUES

Pickering Steam Generator (SG) divider plate sealing skin modifications were performed on Units 1 and 4 and Units 5-8 starting with Unit 4 in 2001 and finishing with Unit 7 in 2004. The primary purpose of this modification was to address divider plate bolt degradation as well as the steady increase in Reactor Inlet Header Temperature (RIHT) due to cross flow through the divider plate which was forcing some units to run derated. The modification, which included installation of sealing skins and new bonnet style locking tabs successfully addressed bolt degradation and reduced RIHT in each unit. However, when unit 5 SG inspections were conducted during the first outage (P551,spring of 2005) following installation of the modification, it was discovered that numerous pieces of locking tabs and sealing skins had broken off in the hot leg (inlet) side of the steam generators due to high cycle fatigue cracking (ref. SCR P-2005-03243). The root causes of this event were deemed to be insufficient design process for the locking tabs and inadequate sealing skin contact with the primary head seat bar. This condition necessitated the change out of skins and installation of new style bendable locking tabs in unit 5 and unit 6 in 2005. These repair campaigns were costly, lengthy and dose intensive totaling approximately $25M, 4 months of outage duration and 100 Rem. Ref. Project #13-40932 and 13-40632 respectively.

During the initial installation of the modification in Units 7 and 8, an improved sealing skin design and added rigor were employed. This resulted in only minor skin damage being observed which eliminated the need to dissemble components and remove the skins, however, locking tab replacement was still required. The new unit 5 and 6 locking tab designs required precision welding and therefore could not be readily installed in-situ. Based on a completed fitness for service assessment, repairs to Unit 7 and Unit 8 could be delayed to as late as 2010 and therefore a new welded keeper locking tab design was proposed which would allow for replacement of the locking tabs in-situ without the costly effort of removal and reassembly of the divider plate components. This had the expected benefits of being more cost effective, shorter duration and less dose intensive.

Installation of the welded keeper locking tab modification was completed in 6 steam generators of unit 7 during the P871 outage (summer of 2008). Lessons learned were subsequently incorporated into the project planning activities for the P1081 outage (spring of 2010) however only 8 of the 12 steam generators scheduled were completed.

Upon completion of the P1081 outage, a comprehensive root cause investigation was conducted to determine the causes for the project exceeding dose, cost and schedule targets. The findings, along with the associated corrective actions which have been incorporated into the project are documented in SCR P-2010-11703.

The major cost variances incurred by the project can be attributed to the following:

1. Underestimation of Project cost ($4.8M)
    - At the time of full release, only the conceptual design had been completed. Final design tolerances were far more stringent than had been anticipated. This lead to greater skill being required to install the modification which resulted in the need for more extensive and costly training. As well, execution estimates were based on qualification testing that was done with a mock up in a shop environment with highly skilled trades personnel. The actual installation conditions, combined with the lesser skills/experience of the available hired trades, caused a much lower productivity than the one achieved during qualification. ($4.8M)

2. Remobilization costs to accommodate the remaining schedule ($4M)
   The original project plan was based on executing two campaigns; one for all of unit 7 and one for all of unit 8.
   - To address operational issues during the P871 outage, only 6 of the 12 SGs were modified. The remaining SGs were postponed to a future outage thus incurring additional facility, training and remobilization costs. ($2M)
   - As a result of not completing the full planned scope in P1081 (see #6 below), additional training costs will be required to complete the remaining scope in the P1281 outage. ($2M)

3. Radiological Discovery Issues ($2.8M)
   - Contingency extension tooling was not available during P871. Traditional attempts to remove discovered hot particles were ineffective. Extended delays were experienced while contingency plans were being developed and executed. ($1.2M)
   - During P1081, excessive quantities of D_2O were found dripping from the SG tubesheets which severely hindered installation activities. This was not anticipated as SGs were dry for all previous campaigns. As well, frequent schedule delays resulted from the need to stop work to remove hot particles in 5 of the 8 SGs. The number of particles encountered were higher than previous campaigns which is likely attributable to a change in decontamination methods. ($1.6M)

4. Costs to develop contingency tooling and installation quality issues ($2.7M)
   - Based on lessons learned from the P871 campaign, contingency extension tooling needed to be developed, tested and qualified to address the presence of hot particles as all work was being performed in-situ. Previous campaigns involved complete disassembly of divider plate components which facilitated hot particle removal and therefore the need for extension tooling was not anticipated in the original release. ($1.5M)
   - Due to the tight design tolerances, bending and welding of the locking tabs/keepers proved to be more difficult than planned which resulted in longer execution duration and quality issues that required rework. This was compounded by the loss of skilled trades just prior to the P1081 outage (see #6 below) ($1.2M)

5. Change in Accounting Practice ($1M)
   - SAVH (Sickness, Accident, Vacation and Holidays) and project support charges were not included in the original project estimate. Subsequent change in accounting practices to include these costs resulted in an increase of approximately $1M.

6. Loss of skilled trades due to Alpha radiation exposure external to OPG (cost impact incorporated into #2 and #4 above)
   - Approximately 1/3 of the trades personnel trained to execute P1081 were removed just prior to the start of the outage due to unknown/unclear Alpha radiation exposures at their previous work location external to OPG. These individuals were subsequently replaced with fewer lesser experienced trades that were able to get only a limited amount of training. Cost variance includes only costs for retraining. Impact to completion of the outage was far greater as this impacted overall productivity and quality and was likely the highest contributor to not completing the full scope of work during P1081.

Locking tab replacements will also be performed on Unit 1 and Unit 4 in Pickering A. This work is being executed under a separate project number. Lessons learned from this project will be incorporated into the Full Release Business Case Summary for Pickering A.

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

3/ ALTERNATIVES & 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							
Base OM&A							
Outage OM&A							
Project OM&A		(39,393)	(19,044)				
Total OM&A	0	(39,393)	(19,044)	0	0	0	0
Capital							
Present Value (PV)		(26,563)	(12,115)				
Net Present Value (NPV)	**N/A**	**(26,563)**	**(12,115)**				
Internal Rate of Return (IRR) %	N/A	N/A	N/A				
Discounted Payback (Yrs)	N/A	N/A	N/A				

Base Case: Not Recommended - Stop the Project
This is not recommended because the locking tabs need to be replaced on all steam generators in Unit 7 and Unit 8 before the 6.3 Effective Full Power Years(EFPY) or the Units will have to be shut down.

Alternative 1: Recommended - Complete locking tab replacement on Unit 7 and Unit 8
We recommend this alternative as it will allow Units 7 and 8 to continue operation beyond the 6.3 EFPY of operation of the locking tabs (currently in 2012) to the unit end of life.

Alternative 2: Not Recommended - Deferring the Project
It is not recommended to defer the project because this would result in Unit 7 and Unit 8 not being returned to operation after completion of their planned 2012 outages.

4/ THE PROPOSAL

The superseding release will be used to complete the locking tab modification on the remaining 6 SGs in Unit 7 and 4 SGs in Unit 8 during the P1271 and P1281 outages respectively and then final closeout of the entire project.

The following are the objectives for this superseding release:

- Implementation of corrective actions as a result of lessons learned and the root cause evaluation including;
  - Design reviews/updates to improve constructability
  - Tooling modifications to increase productivity
  - Supporting development of alternate SG decontamination methods to reduce radiation fields and occurrence of hot particles
  - Development of improved execution documentation (eg. work plans, training and ALARA plans)
- Completion of pre-installation activities and training for Unit 7 & 8
- Completion of locking tab installation on SGs 4, 5, 6, 8 (only locations 22, 23, 24 & 25) 10, 11,& 12 in Unit 7 during its planned 2012 outage
- Completion of locking tab installation on SGs 2, 3, 8, & 9 in Unit 8 during its planned 2012 outage
- Completion of post-installation inspections on all remaining locking tab installations
- Completion of final AFS and closeout activities for both Units 7 & 8

5/ QUALITATIVE FACTORS

There are no qualitative factors.

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

6/ RISKS ANALYSIS (See Attachment D for details)

Low 1 to 3	Medium 4 to 9	High 10 to 25

Probability \ Impact	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	Mitigation	Probability X Impact: Finance	Schedule	Quality	Corporate Reputation	Regulatory	Health & Safety	Environmental	Nuclear Safety	Risk Rating (1 to 25)
Higher than anticipated costs for initiatives to improve the design and/or implementation methods.	OPG will work closely with the contractor to limit proposed changes to those with tangible benefits and will ensure improvements can be actually realized in the field (through the qualification process).	Before	12	12	8	4	4	4	4	4	12
		After	6	6	4	2	2	2	2	2	6
Potential for cost increase and schedule delay during execution due to interference with other outage work programs or discovery work.	Co-ordinate outage activities with the Outage SWC. Utilize resource sharing where possible to reduce costs.	Before	3	9	3	3	3	3	3	3	9
		After	1	3	1	1	1	1	1	1	3
Potential for cost increase and schedule delays during execution due to delays caused by radiological conditions in the steam generators (eg. hot particles,D2O dripping, passing isolation).	Extension tooling will allow work to be performed with workers outside the steam generator bowls. Project will be working with RP to develop effective methods to remove hot particles and decontaminate the steam generators to reduce radiation fields. Note, radiation fields which prohibit work at the open manway and passing isolation remain risks outside of project control /mitigation.	Before	20	20	15	10	10	10	5	5	20
		After	8	8	4	4	4	4	2	2	8
Potential for cost increase and schedule delay due to construction productivity and quality issues.	Develop improved training plan which incorporates implementation details and pass/fail criteria. Revise design to increase tolerances and eliminate traditionally high rework elements where possible. Develop alternate schedules to increase wrench time. OPG to closely monitor execution performance.	Before	15	15	8	4	4	4	4	4	12
		After	6	[illegible]	3	2	2	2	2	2	6

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Tooling and material costs higher than estimated.	Scope will be limited to only those changes with tangible benefits as documented in Lessons Learned.	Before	9	9	6	3	3	3	3	3	9
		After	3	3	2	1	1	1	1	1	1
Additional costs for unforeseen training requirements (due to skills / inexperience of the trades) and extended training schedule.	The skills / experience of the trades will be tested prior to hire on (eg. welding tests). A comprehensive training plan will be developed and closely monitored to ensure efficiency and quality. Lessons learned from previous training sessions will be incorporated.	Before	9	9	6	3	3	3	3	3	9
		After	3	3	2	1	1	1	1	1	3
P1271 and P1281 Outage schedule changes.	Projects will maintain close communication with the Outage manager for schedule changes; the hire on plan will be adjusted accordingly.	Before	6	6	4	4	4	4	4	4	6
		After	2	2	1	1	1	1	1	1	2
Skilled construction resources not available due to competing work.	Complete design review/update to increase tolerance for elements which require high level of skill to allow resources to be drawn from other trades unions. Communicate in advance with union halls to alert them of upcoming work.	Before	8	8	8	2	2	2	2	2	8
		After	2	2	2	1	1	1	1	1	2
Potential for safety related events during site execution due to conventional and radiological hazards.	Training will be conducted in representative conditions and mockups. Improved decontamination methods and localized shielding will be developed. Execution schedule/logic will be adjusted to allow additional time for SG draining.	Before	9	9	6	9	6	**12**	3	4	**12**
		After	1	1	1	1	1	3	1	1	3
Dose uptake is higher than outlined in the ALARA plan.	Hot particle removal contingency plans will be developed and practiced in advance. Improved decontamination methods will be used. Contingency extension tooling could be used to reduce in-bowl time.	Before	8	**20**	8	**12**	8	**12**	4	4	**20**
		After	2	5	2	3	2	3	1	1	5
Tight design tolerances remain unchanged leading to potential for continued high levels of rework and need for large quantity of very skilled trades resources.	Modify training plans to focus on past high rework activities. Utilize most skilled resources for this area to conserve dose.	Before	**16**	**16**	12	8	4	8	4	4	**16**
		After	4	4	3	2	1	2	1	1	4

Specific contingencies have been allocated for each of the project risks.

7/ POST IMPLEMENATION REVIEW

Type of PIR:	Targeted Final AFS Date:	Targeted PIR Approval Date	PIR Responsibility (Sponsor Title)
Simplified	12-Dec-12	19-Dec-14	Components & Equipment

	Measurable Parameter	Current Baseline	Targeted Result	How will it be measured?	Who will measure Person / Group?
1.	Durability of Steam Generator divider plate fastener locking device	Unit 7 and 8 steam generators were found with several broken locking tabs	Divider plate locking device to remain intact until end of SG life.	Perform locking tab inspections during the P1471 and P1481 outages to ensure locking tabs remain intact.	Major Components Section, Components & Equipment Department

APPENDIX "A" GLOSSARY (acronyms, codes, technical terms)

- AFS: Available for Service
- ALARA: As Low As Reasonably Achievable
- D2O : Heavy Water
- EC: Engineering Change
- EFPY: Effective Full Power Year
- EOL: End of Life
- HTS: Heat Transport System
- LOCA: Loss of Coolant Accident
- NPV: Net Present Value
- PHT: Primary Heat Transport
- PNGS: Pickering Nuclear Generator
- SG: Steam Generator

APPENDIX "B" Comparison of Total Project Estimates

$ 000's		This Appendix compares the Total Project Estimate for each BCS Existing and Planned BCS's Total Project Estimate by Year (incl Contingency)									Total Project
BCS Type	Month	Year	2007	2008	2009	2010	2011	2012	2013	Later	Est
Full	Mar	2007	13,326	3,148	0	3,990	61				20,525
Superseding	Oct	2010	421	7,807	389	12,530	817	17,128	301		39,393
											0
											0
											0
											0
											0
											0

Comments:

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
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APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

Financial Assumptions:

Discount Rate:	7%	Cost Escalation (Yr)	2%	SR&D Opportunity	No
Progress Payments	No	Foreign Currency	No	Retainer Fee	No
Depreciation Rate (Capital)	N/A	PST	No	Interest Rate (Capital)	OM&A N/A
Revenue Rate	Corp SEV	Leasing	No	Indexed Priced Contract	No

Comments:

Project Cost Estimate:

Design Complete:	100%	Fixed Price Contract	No	3rd Party Estimate	No
Quality of Estimate	Release +15% to -10%	OPEX used	Yes	Lessons Learned	Yes
Similar Projects	No	Budgetary Quote	No	First Unit Actual Used	No
Firm Vendor Proposal	Yes	Cost Sharing	No	Competitive Bid	No
Reviewed by Sponsor	Yes	Fee for Service	No	Contracts in place	Yes

Comments:

Rationale for Capital Cost Classification:

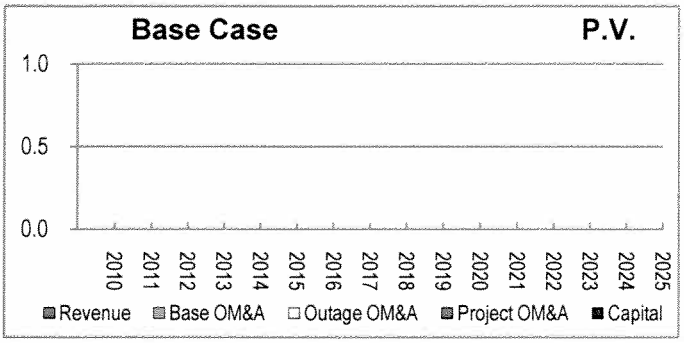
Generation Plan Assumptions:

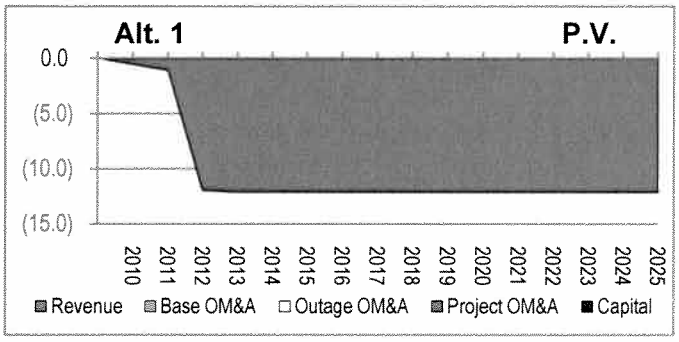
Station	Unit	EOL or Refurb	MW	Capacity	Planned Outages for Project Work					
Pickering A	1	Jun-20	515	85%						
	4	Jun-20	515	85%						
Pickering B	5	Nov-18	516	88%						
	6	Nov-18	516	88%						
	7	Jun-20	516	88%	P1271					
	8	Jun-20	516	88%	P1281					
Darlington	1	Sep-16	878	92%						
	2	Jul-18	878	92%						
	3	Apr-20	878	92%						
	4	Dec-21	878	92%						

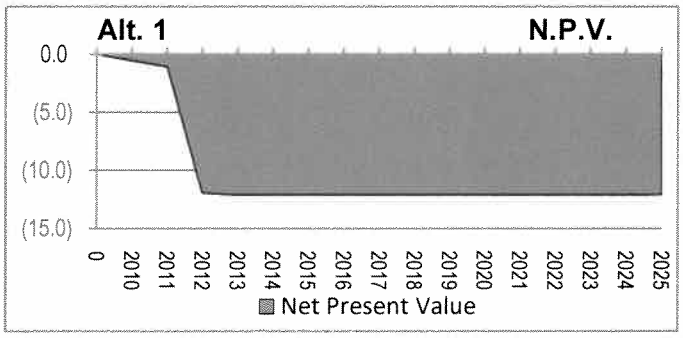
Comments:

APPENDIX "C" FINANCIAL MODEL – ASSUMPTIONS

Impact on Operations







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Business Case Summary

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ATTACHMENT "A" PROJECT COST SUMMARY

	$ 000's OM&A	LTD 2009	2010	2011	2012	2013	2014	2015	Later	Total
Accounting Basis	Project Mgmnt & Support	1,376	786	363	541	145				3,212
	Engineering	274	134	43	252	29				733
	Procurement	367	431	-	700	-				1,498
	Construction	6,600	11,173	116	12,181	73				30,143
	Other		6	10	187	4				207
										-
										-
										-
	Interest (Capital Project)									-
	Project Costs	**8,617**	**12,530**	**533**	**13,862**	**251**	**-**	**-**	**-**	**35,793**
	General Contingency		-							-
	Specific Contingency			284	3,266	50				3,600
	Project Costs	**8,617**	**12,530**	**817**	**17,128**	**301**	**-**	**-**	**-**	**39,393**

	$ 000's OM&A		LTD 2009	2010	2011	2012	2013	2014	2015	Later	Total
Funding Basis	Current Release	Project Costs	8,617	7,588							16,205
		Contingency	-	4,320							4,320
		Total	**8,617**	**11,908**	**-**	**-**	**-**	**-**	**-**	**-**	**20,525**
	This Release	Project Costs		4,942	533	13,862	251				19,588
		Contingency		(4,320)	284	3,266	50				(720)
		Total	-	622	817	17,128	301	-	-	-	**18,868**
	TTD Released	Project Costs	8,617	12,530	533	13,862	251	-	-	-	35,793
		Contingency	-	-	284	3,266	50	-	-	-	3,600
		Total	**8,617**	**12,530**	**817**	**17,128**	**301**	**-**	**-**	**-**	**39,393**
	Future Releases	Project Costs								(0)	(0)
		Contingency								-	-
		Total	-	-	-	-	-	-	-	(0)	(0)
	Project Funding		**8,617**	**12,530**	**533**	**13,862**	**251**	**-**	**-**	**(0)**	**35,793**
	Contingency Funding		**-**	**-**	**284**	**3,266**	**50**	**-**	**-**	**-**	**3,600**
	Total Funding		**8,617**	**12,530**	**817**	**17,128**	**301**	**-**	**-**	**(0)**	**39,393**

Budget	2010 - 2014 Business Plan	8,617	9,312	211						18,140
	Variance to Budget	0	3,218	322	13,862	251	0	0	(0)	17,653

Other	Removal Costs (above)									-
	Inventory W / O									-
	Spare Parts in Invent									-

Reviewed by:	(Date)	Approved by:	(Date)
	Oct 26/2010		26 OCT 2010
E.H. Wong Project Manager		Nahil Rahman Strat IV Manager	

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

ATTACHMENT "B" PROJECT VARIANCE ANALYSIS

	OM&A	LTD Sep 2010	Total Project: Last BCS Mar 2007	Total Project: This BCS Oct 2010	Variance	Comments
Scores Basis	Project Mgmnt & Support	2,107	1,225	3,212	1,988	see note 1
	Engineering	408	229	733	505	see note 2
	Procurement	798	203	1,498	1,296	see note 3
	Construction	17,324	14,550	30,143	15,594	see note 4
	Other			207	207	see note 5
					-	
					-	
					-	
					-	
	Interest (Capital Project Only)				-	
	Project Costs (Scores Basis)	**20,637**	**16,205**	**35,793**	**19,588**	
	General Contingency		**4,320**		(4,320)	
	Specific Contingency			3,600	3,600	see note 6
	Project Costs (Scores Basis)	**20,637**	**20,525**	**39,393**	**18,868**	

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

Comments:

Note 1: Increased Project Management & Support Costs:

- Increased support required during execution due to installation delays and rework.
- Additional Project personnel were required during the testing and qualification of extension tooling.
- Additional costs due to 2 year increase in project duration.
- The addition of SAVH has been budgeted for in this estimate.

Note 2: Increased Engineering Costs:

- Additional Design Engineering resources were required for extension tooling development and qualification during pre-installation, training and execution phases of the project.
- The addition of SAVH has been budgeted for in this estimate.

Note 3: Increased Procurement Costs:

- The original cost for locking tab keepers required for installation was underestimated in the full release budget.
- Additional locking tab keepers were required during qualification testing and training which were not accounted for in the original budget.
- Additional material required to support 2012 training sessions

Note 4: Increased Construction Costs:

- One third of the hired and trained Trades personnel were not granted radiation worker rights for the P1081 Outage due to Alpha particle contamination external to OPG. Additional Trades personnel had to be hired to replace these individuals. Extra training time was required to train the new hires for the installation phase. The additional hired trades were only able to get a limited amount of training prior to the start of installation which contributed to the quality issues during installation.
- Additional Trades personnel hours were required to manufacture additional keepers to be used during the training and installation phases.
- Additional costs were incurred during execution due to delays and rework.
- Delays caused by dripping water in the steam generators, hot particles in the steam generators, and stuck bolts during installation of new hardware. Rework was required on locking tab keepers that were inadequately installed and did not meet design specifications.
- Additional costs were incurred to develop, test and qualify extension tooling to be used in the steam generators during execution to reduce the amount of time trades personnel had to be in the steam generator bowls which would help to reduce dose rates.
- During P871 a hot particle in steam generator 8 caused a lengthy delay to the installation of locking tabs. Trades personnel were kept available to complete the installation once the hot particle was removed. This risk was not identified in the Full Release Business Case Summary and was not budgeted for in the original estimate.

Note 5: Other Costs:

- This cost is the Project Support charge which is charged on the entire project cost. When the Full Release Business Case Summary was released for this project, the Project Support charge did not exist so it was not budgeted for in the original estimate. Project Support was introduced in 2010 for OM&A projects.

Note 6: Specific Contingency

- Risk management level was deemed "extensive" based on the project's risk rating. As such, all contingency has been allocated against specific risks. The specific contingency was calculated based on the probability and cost impact of the risks outlined in the risk table contained in the project execution plan. Specific contingency has been allocated under the following areas:

Risk Area	Specific Contingency Amount
Radiological Hazards & Conditions	$1.3M
Higher than anticipated cost to improve implementation	$0.3M
Availability and training of resources	$0.4M
Execution productivity and quality issues	$0.8M
Interference with other outage work programs	$0.3M
Tooling & Material Issues	$0.5M
Total	$3.6M

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

ATTACHMENT "C" **SCHEDULE**

Key Milestones

Completion Date	Description
1-Nov-11	Unit 7 Installation Labour Contracts Awarded
1-Oct-12	Unit 7 Start of Installation P1271
12-Dec-12	Unit 7 Available for Service Complete
1-Apr-11	Unit 8 Installation Labour Contracts Awarded
1-Mar-12	Unit 8 Start of Installation P1281
14-May-12	Unit 8 Available for Service Completed
12-Dec-13	Project Complete Milestone

A Project Execution Plan (PEP) will be approved by 11-Nov-10

In Service Declarations: (Capital only)

Date	Description	$000's	% In Service

Comments:

Pickering B Steam Generator Locking Tab Replacement 13 - 40641 (OM&A)
Superseding Business Case Summary NK30 - BCS - 33115 - 00008 - R000

Risk Probabilities Chart

Likelihood	Improbable	Unlikely	Possible	Likely	Probable
Probability	<= 1 in 100	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 month	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 > $15MCat. 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 ORMajor 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 OrderCat. 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 finesORPotential 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 spillsEmission in exceedance of regulatory or legal limitsField orders or AMP'sPublic complaints with OPG implicationsDanger 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 scheduleORPossibility 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 - reportableAdministrative infractionsPublic 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-complianceORRoutine approval / notification	No medical attention beyond first aid, no impairment to worker or complete recovery of worker	Administrative, non-reportable eventsCat. C spills non-reportable and spills resulting from Acts of God	

ONTARIO POWER GENERATION

Records File Information:
Records SCI/USI Retention
- See Guidance Section

OPG Confidential

OPG-FORM-0076-R005*

Type 3 Business Case Summary

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

Executive Summary and Recommendations

Project Information			
Project #:	16-80067	**Document #:**	D-BCS-35361-10001 R00
Project Title:	DN IFB Stacking Frame Replacement (Long Bundle)		
Class:	☒ OM&A ☐ Capital ☐ Capital Spare ☐ MFA ☐ CMFA ☐ Provision ☐ Others:	**Investment Type:**	Sustaining
Phase:	Execution	**Release:**	Partial
Facility:	Darlington	**Target In-Service or Completion Date:**	2022-12-30

Project Overview

We recommend the release of $9,368 k, including [redacted] of contingency.
The estimated total project cost is $ 32,963 k, including [redacted] of contingency.

The quality of the estimate for this release is Class # 4 (-30% to +50%), and for the total project is Class #4 (-30% to +50%).

This release will fund the following scope of work:

1) Award of Phase I (Replacement of 18 Standard Stacking Frames with Long Stacking Frames) Installation Contract
2) Floor loading assessments of areas to be used for handling of the Stacking Frames in the East & West Fuelling Facilities Auxiliary Areas (FFAA)
3) Work planning (workplan preparation, work order assessment, work package preparation) for replacement of twenty seven (27) stacking frames.
4) Selection and Purchase of tooling for decontamination and cutting of Standard Stacking Frames
5) Material procurement for 3 years (27 Long Stacking Frames)
6) Removal/Decontamination/Cutting/Disassembly and Disposal of Eighteen (18) standard stacking frames during 2015 & 2016.
7) Installation of Eighteen (18) Long Stacking Frames during 2015 & 2016.
8) Update of the Project Oversight Plan for Phase II
9) Completion of front end planning, Project Management Plan (PMP) and preparation of Execution Business Case Summary (Full Release)

Problem Statement/Business Need:

Darlington Irradiate Fuel Bays (IFBs) in the East & West Fuelling Facilities Auxiliary Areas (FFAAs) are running out of storage space to store the Irradiated Fuel (I/F) bundles. The Irradiated Fuel bundles are stored within the storage modules, which are stacked into the Stacking Frames (SFs). As Darlington has switched to the use of longer fuel bundles, the Standard Stacking Frames (SSFs) can no longer be used for their storage and need to be replaced with the Long Stacking Frames (LSFs). There are currently 70 Standard Stacking Frames (30 in the East & 40 in the West IFBs) and 65 Long Stacking Frames in the East & West IFB (40 in the East and 25 in the West IFB). The East and West IFBs have been designed to accommodate 78 and 72 Long Stacking Frames respectively.

Space for installation of new long stacking frames in the West Storage Bay is limited and will reach critical status by the end of Q2 of 2015. After the limit is reached, Trolley T(1,2) will be out of service with no room to discharge fuel in the WFFAA and Trolley T(3,4) will be forced to fuel out of the EFFAA. Reference SCR D-2013-04247. The East Storage Bay which has about 2 years fuel storage room remaining will also be in a critical state by 2016.

Also, in support of Darlington refurbishment, additional fuel storage space is needed to accommodate two core discharges to the WFFAA during 2016-2019.

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

Type 3 Business Case Summary

Project #: 16-80067 Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Project Overview

Summary of Preferred Alternative:

In order to meet the on-going Station I/F discharge needs and to provide additional irradiated fuel storage space in advance of Darlington Unit 2/3 refurbishment, Standard Stacking Frames (SSF) need to be replaced with Long Stacking Frames (LSF). This replacement is required to accommodate the Long fuel bundles which can no longer be stored in standard stacking frames. Due to lack of Fuel Handling Maintenance resources, this project has been initiated to replace 70 Standard Stacking Frames with Long Stacking frames over a period of 8 years.

The project has been divided into two phases. This Partial Execution BCS covers the first phase of the project to allow replacement of 18 standard stacking frames (during 2015/2016). Phase I will provide the required space to accommodate the core dump for Darlington Unit 2 refurbishment. In Phase II the remaining 52 SFs will be replaced, bringing the total of the replaced SF to 70.

In order to ensure continuity of work and allow project to meet all N-PROC-MA-0022 ""Integrated On-line Work Schedule" milestones, purchase and assessment work for 9 Stacking Frames belonging to Phase II will be covered in Phase I. The actual replacement work for these 9 SFs will be covered in Phase II (future release).

History of BCS releases and project cost estimates:

This BCS is the first funding release for the project.

History of scope and schedule changes:

This BCS captures the original project scope & schedule and is in line with the project charter [R-1] requirements.

Key Assumptions and Risks:

Prior to removal of Standard Stacking Frames from the IFB, the SFs need to be emptied. It requires 7 Dry Fuel Storage Containers (DSC) to empty a SSF. The current rate of Dry Fuel Storage Containers (DSC) transfer is 60 DSCs per year. At this rate ~ 8.5 Stacking frames will be emptied. The project charter requires the project to replace 9 stacking frames/year which translates into 63 DSCs (i.e. 7 DSCs per Stacking Frame) to be transferred. This discrepancy in the DSC transfer rate (of 3 DSCs per year) and the project requirements can delay completion of the project by one (1) year. Based on discussion with Darlington Fuel Handling this discrepancy in the DSC transfer rate will not impact the project as Fuel Handling will make up this difference by transferring modules from standard to long stacking frames to ensure there are enough empty standard stacking frames available to the Project to meet the replacement target of 9 SFs per year.

The Standard Stacking Frames will be cut and placed in standard bins 47"X52"X72" (Cat ID: 490723) and then shipped to Nuclear Waste Management Division (NWMD) Bruce Site as Lowe Level Radioactive Waste by Darlington Waste Handling. This approach has been accepted in principle by the NWMD but the formal acceptance of the Radioactive Waste Notification, RWN#: 14-D-017 is still in progress and is expected before end of 2014.

It is expected that any Engineering documents (specifications, calculations and assessments) prepared for carrying out the SF replacement work will be treated as vendor technical documents and will not require creation of any Engineering Changes under the Risk Based Modification process.

In the past Fuel Handling Maintenance have been installing Long Stacking Frames in the IFBs but removal of the Standard Stacking Frames is first of a kind evolution and has never been performed previously.

As part of the Project work removal of the Standard Stacking Frames and Installation of Long Stacking Frames will be completed by a ES MSA Contractor. OPG (Projects & Modifications) will provide workplan and oversight to the contractor to carry out this work. It is expected that contractor will use trained/qualified staff for completing this work including operation of station cranes.

OPG will be procure 70 Long Stacking Frames (Cat ID: 497180) and will deliver to site for installation by the contractor.
OPG will also procure ~ 210 standard waste bins (Cat ID: 490723) for the disposal of the SSFs. The cost of SSF and Standard Waste Bins has been budgeted in the project cost.

It should be noted that the scope of the EPC contract is mainly construction (Removal/Installation of Stacking Frame) with limited Engineering scope and potential procurement scope if custom tooling is to be bought. Any tooling required for the removal, decontamination, cutting & disposal and installation will be provided by the contractor.

Type 3 Business Case Summary

Document #: D-BCS-35361-10001 R00

Project #: 16-80067
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Project Cash Flows, NPV, and OAR Approval Amount

k$	LTD	2014	2015	2016	2017	2018	2019	Future	Total
Currently Released	0	0	0	0	0	0	0	0	0
Requested Now	-	30	4,279	4,346	713	0	0	0	9,368
Future Required	-	0	0	0	3,343	3,963	3,963	12,326	23,595
Total Project Cost	0	30	4,279	4,346	4,056	3,963	3,963	12,326	32,963
Ongoing Costs	-	0	0	0	0	0	0	0	0
Grand Total	0	30	4,279	4,346	4,056	3,963	3,963	12,326	32,963

Estimate Class:	Class 4	**Estimate at Completion:**	[redacted]
NPV:	N/A	**OAR Approval Amount:**	$9,368 k

Additional Information on Project Cash Flows (optional):

- Contract costs are based on contractor and third party estimates.
- Class 4 estimate for the entire project.
- Dry Fuel Storage organization support costs for the transfer of Dry Fuel Storage Containers (DSCs) are not included in the BCS.
- Darlington Waste Handling cost for shipping the standard bins to NWMD (Bruce Site) is not included in the BCS.

Contingency Breakdown:

- Current Release specific contingency of [redacted] was calculated based on Moderate Risk Management Strategy and contractor OPEX (cost performance).
- [redacted] escalation cost per year has been added (as contingency) to OPG staff rates, material and contractor costs beyond 2015.
- [redacted] of the ES MSA vendor contract (Phase I) value added as specific contingency to cater for any potential performance fee bonus to the vendor.
- Future Release general contingency = [redacted] (through use of risk tables for Minor Risk Management strategy). In addition to general contingency, [redacted] of the ES MSA contract (Phase II) value added as specific contingency to cater for any potential performance fee bonus to the contractor.

Approvals

	Signature	Comments	Date
The recommended alternative, including the identified ongoing costs, if any, represents the best option to meet the validated business need.			
Recommended by (Project Sponsor): Glenn Jager, Chief Nuclear Officer		Hold prior to contract award. Explanation of why estimate >100% higher than 3rd party. Execution gains expected.	18 DEC 2014
I concur with the business decision as documented in this BCS.			
Finance Approval: Beth Summers, SVP & Chief Financial Officer, per OPG-STD-0076			22 DEC 2014
I confirm that this project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: for Mike Martelli, Tom Mitchell, President & CEO, per OAR 1.1			23 Dec 14

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Business Case Summary

Part A: Business Need

Darlington Irradiate Fuel Bays (IFBs) in the East & West Fuelling Facilities Auxiliary Areas (FFAAs) are running out of storage space to store the Irradiated Fuel (I/F) bundles. The Irradiated Fuel bundles are stored within the storage modules, which are stacked into the Stacking Frames (SFs).

At the current fueling rate, Darlington discharges about 24,000 irradiated fuel (I/F) bundles per year, which fills up 9 Stacking Frames. The I/F bundles have to be kept in the Stacking Frames for 10 years or more, before they can be transferred to Dry Fuel Storage. Dry Fuel Storage has a target of 60 Dry Storage Containers (DSC) loading per year, which equates to 8.5 Stacking Frames.

As Darlington has switched to Long Fuel Bundles, the Standard Stacking Frames can no longer be used to store the I/F bundles, hence the Standard Stacking Frames need to be replaced with the Long Stacking Frames to cater for on-going fueling needs.

Space for installation of new long stacking frames in the West Storage Bay is limited and will reach critical status by the end of Q2 of 2015. After the limit is reached, Trolley T(1,2) will be out of service with no room to discharge fuel in the West FFAA and Trolley T(3,4) will be forced to fuel out of the East FFAA. Reference SCR D-2013-04247. The East Storage Bay which has about 2 years fuel storage room remaining will also be in a critical state by 2016.

Also, in support of Darlington refurbishment, additional fuel storage space is needed to accommodate two core discharges to the WFFAA during 2016-2019.

In order to meet the station I/F discharge needs the target performance for removal and disposal of Standard Stacking Frames is 9 per year until all 70 Standard Stacking Frames have been replaced with Long Stacking Frames in the fuel bays. The replacement work needs to be started at the end of Q2 of 2015 at the latest to ensure there is no impact on unit fueling activities.

Part B: Preferred Alternative: Projects & Modifications to carry out replacement of 70 Standard Stacking Frames (2015-2022)

Description of Preferred Alternative

The replacement of 70 Standard Stacking Frames at a rate of 9 Stacking Frames per year will be carried out by Projects and Modification division. A two phase approach will be used to complete the project scope. In the first Phase (Phase I), an Engineer, Procure and Construct (EPC) contract will be established for the replacement of eighteen (18) Standard Stacking Frames. Phase I work will start in December 2014. The SF replacement work for Phase I will start in late Q2 of 2015 and replacement of 18 SFs is expected to be complete by the end of year 2016.

In the Second Phase (Phase II), the replacement of the remaining fifty two (52) Standard Stacking Frames will be completed through an EPC contract during 2017 to 2022. The project close-out will be completed by June 30, 2023.

OPG will purchase the already designed Long Stacking Frames (Cat ID: 497180). Work will be carried out under OPG's Quality Assurance program. OPG will be responsible for work planning (including workplan preparation, work order assessment and work package preparation). Work will be carried out as per N-PROC-MA-0022 "Integrated On-line Work Schedule". The contractor will be carrying out the Removal/Decontamination/Cutting/Disassembly/Disposal and installation of the Long Stacking Frames.

The current release covers the following scope:

1) Removal/Decontamination/Cutting/Disassembly and Disposal of Eighteen (18) standard stacking frames during 2015 & 2016 by Contractor.
2) Installation of Eighteen (18) Long Stacking Frames during 2015 & 2016 by Contractor.
3) Engineering Scope to be completed prior to start of replacement work by the Contractor:
    a. Floor loading assessment for areas used for handling of Stacking Frames.
    b. Selection and design of any tooling (if off-the shelf tooling is not available) required for handling, cutting and disposal of Stacking Frames including any engineered scaffolds/rigging arrangements.

*Associated with OPG-STD-0076, Developing and Documenting Business Cases

Part B: Preferred Alternative: Projects & Modifications to carry out replacement of 70 Standard Stacking Frames (2015-2022)

Description of Preferred Alternative

4) Procurement (by Contractor) of any tooling required for handling, cutting and disposal of Stacking Frames if standard off-the shelf tooling is not available or cannot be used.
5) Procurement of twenty seven (27) Long Stacking Frames by OPG

NOTE: Although Phase I only covers replacement of 18 Stacking Frames but in order to ensure continuity of work beyond 2016, additional 9 stacking frames (for Phase II) will be procured for year 2017 under the current release.

6) Work planning (workplan preparation, work order assessment, work package preparation) for replacement of twenty seven (27) stacking frames by OPG.

NOTE: Although Phase I only covers replacement of 18 Stacking Frames but in order to ensure continuity of work beyond 2016, assessment will be completed for an additional 9 stacking frames (for year 2017) under the current release.

Deliverables:	Associated Milestones (if any):	Target Date:
Current Release:		
Phase I (Replacement of 18 Standard Stacking Frames) Installation Contract awarded	ICA (Installation labour contract awarded)	17-FEB-2015
Phase I Start of Stacking Frame Replacement	SOI (Start of Installation)	30-JUN-2015
Replacement of 18 Standard Stacking Frames Completed	AFS (Ready for Service)	30-DEC-2016
Future Release:		
Phase II (Replacement of 52 Standard Stacking Frames) Installation Contract awarded	ICA (Installation labour contract awarded)	31-AUG-2016
Replacement of 52 Standard Stacking Frames Completed	AFS (Ready for Service)	30-DEC-2022
Project Complete	PCM (Plan Complete)	30-JUN-2023

Part C: Other Alternatives

Summarize all viable alternatives considered, including pros and cons, and associated risks. Other alternatives may include different means to meet the same business need, and a reduced or increased scope of work, etc.

Alternative 2: Base Case – No Project

If this project does not proceed, the risk of unit de-rating / shutdown will be high. Fueling capability will be affected in about a year. Unit de-rates / shutdown due to loss of fuelling capability can result if urgent work to restore fuel storage capability (emptying & removal of standard stacking frames and installation of Long Stacking Frames) is not done.

The removal of standard stacking frames and replacement with the long stacking frames is needed to maintain fuelling capability. Trolley T(1,2 will go out of service by 2015 if action is not taken to create additional fuel storage capacity in the WFFAA. With reduced fuelling capability, this will be followed by Unit de-rates and/or shutdown with only 2 remaining trolleys to fuel 4 operating units. The East Storage Bay which has about 2 years fuel storage room remaining will also be in a critical state by 2016.

Also, in support of Darlington refurbishment, additional fuel storage space is needed to accommodate two core discharges to the WFFAA during 2016-2019.

Alternative 3: Delay Work –Beyond Q2 of 2015

Based on the details outlined in Alternative 2, project work cannot be further delayed.

Alternative 4: Projects & Modifications to carry out replacement of 18 Standard Stacking Frames (2015-2016) and Station to complete or manage the remaining 52 Stacking Frame replacement

As per the Project Charter (D-PCH-35361-10001), the Stacking Frame replacement work is currently beyond the capability of Fuel Handling Maintenance organization. Hence this work is being carried out as a project. After completion of Phase I (2015/2016), station will need to provide internal resources to complete the remaining work internally.

With Fuel Handling Maintenance completing the work, the challenges around coordination between several OPG work groups (Fuel Handling OPS, IMS and Dry Fuel Storage Group) will be reduced and the cost could be better managed as the resources could be re-deployed easily to other work if any scheduling issues like delay in emptying of Stacking Frame or Lack of crane availability were encountered.

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Alternative 5: N/A

Part D: Project Cash Flows, NPV, and OAR Approval Amount

k$	LTD	2014	2015	2016	2017	2018	2019	Future	Total
Currently Released	0	0	0	0	0	0	0	0	0
Requested Now	-	30	4,279	4,346	713	0	0	0	9,368
Future Required	-	0	0	0	3,343	3,963	3,963	12,326	23,595
Total Project Cost	0	30	4,279	4,346	4,056	3,963	3,963	12,326	32,963
Ongoing Costs	-	0	0	0	0	0	0	0	0
Grand Total	0	30	4,279	4,346	4,056	3,963	3,963	12,326	32,963

Estimate Class:	Class 4	**Estimate at Completion:**	[redacted]
NPV:	N/A	**OAR Approval Amount:**	$9,368 k

Additional Information on Project Cash Flows (optional):

- Contract costs are based on contractor and third party estimates.
- Class 4 estimate for the entire project.
- Dry Fuel Storage organization support costs for the transfer of Dry Fuel Storage Containers (DSCs) are not included in the BCS.
- Darlington Waste Handling cost for shipping the standard bins to NWMD (Bruce Site) is not included in the BCS.

Contingency Breakdown:

- Current Release specific contingency of [redacted] was calculated based on Moderate Risk Management Strategy and contractor OPEX (cost performance).
- [redacted] escalation cost per year has been added (as contingency) to OPG staff rates, material and contractor costs beyond 2015.
- [redacted] of the ES MSA vendor contract (Phase I) value added as specific contingency to cater for any potential performance fee bonus to the vendor.
- Future Release general contingency = [redacted] (through use of risk tables for Minor Risk Management strategy). In addition to general contingency, [redacted] of the ES MSA contract (Phase II) value added as specific contingency to cater for any potential performance fee bonus to the contractor.

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case	Delay Work	Alternative 4	
Project Cost	32,963	N/A	N/A	N/A	
NPV	N/A	N/A	N/A	N/A	
Other (e.g., IRR)	N/A	N/A	N/A	N/A	

Summary of Financial Model Key Assumptions or Key Findings:

As per OPG-STD-0076, an economic justification is not required for Sustaining Projects.

Part F: Qualitative Factors

N/A

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	There is a risk that a cost over-run may occur if the estimated cost for the phase is too low. No Stacking Frame removal, decontamination and disposal has been carried out at Darlington in the past. There is no historical cost data available.	Accept: Project team will closely monitor project cost. Specific contingency may be needed to address the risk if it materializes. Contingency will be carried for this risk.	Medium	Medium
Schedule	There is a risk that Stacking Frame replacement work is impacted (delayed) by the work being performed by other work groups. As SF replacement work requires coordination with several work groups (Dry Fuel Storage Group, Fuel Handling Operations, Fuel Handling Maintenance, Crane/Supertool Maintenance, IMS and Projects & Modifications) to allow access to the East & West FFAAs.	Mitigate: The work in the field will be carried out as per N-PROC-MA-0022 "Integrated On-line Work Schedule" to minimize impact of other work in the East & West FFAA. Also, SF replacement schedule will be developed based on other work going on in the East & West FFAA.	Medium	Medium
Schedule	There is a risk that Replacement (Removal/Decontamination of Standard Stacking Frames (SSFs) and Installation of Long Stacking Frames (LSFs)) is delayed due to delay in emptying of the SFs. This delay can occur if the Dry Fuel Storage Containers (DSC) transfer is delayed due to issues with the station cranes, DSC transfer equipment or execution of other maintenance or project work in the East & West FFAAs.	Mitigate: This risk will be mitigated by carrying out the SF replacement work in accordance with the N-PROC-MA-0022 "Integrated On-line Work Schedule". Also, project will define the DSC transfer schedule with the DSC group and Fuel Handling Engineering at least 21 weeks before start of the replacement work.	Medium	Low
Resources	There is a risk that Due to other large scale station work like Vacuum Building Outage and Darlington Unit 2/3 refurbishment, there is potential that resources could be scarce.	Mitigate: 1) Project is going to obtain resource commitment from the contractor prior to start of the work. 2) Contractor is responsible to work with Union halls and staff project appropriately to support the project schedule.	Medium	Medium
Schedule	The SF replacement work was assigned to PWU as per the CPAA work assignment. A PSA was initiated to contract out the SF replacement work due to lack of availability of OPG Fuel Handling and other Maintenance resources. The PSA has not been approved yet. If the PSA is not approved or takes longer to resolve (beyond December 12, 2014, planned contract award date) then start of the SF replacement work may be delayed beyond Q2 of 2015.	Mitigate: Confirmation from station resources has been obtained that they are unable to support the SF replacement work. Projects to expedite resolution/approval of the PSA.	Low	Medium
Other	There is a risk that The current rate of Dry Fuel Storage Containers (DSC) transfer is 60 DSCs per year. At this rate ~ 8.5 Stacking frames will be emptied. The project	Mitigate: In order to mitigate this potential delay in completing the project, either the rate of transfer will have to be increased from 60-63 or other actions will need to be	High	Medium

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
	charter requires the project to replace 9 stacking frames/year which translates into 63 DSCs (i.e. 7 DSCs per Stacking Frame) to be transferred. This discrepancy in the DSC transfer rate and the project requirements can delay completion of the project by one (1) year. This issue may materialize as early as 2016 as there may not be extra empty SF available by that time.	implemented by Fuel Handling. These actions may include temporary movement/storage of Fuel Modules in other stacking frames to allow emptying of 9 stacking frames in each year.		

Additional Risk Analysis:

Refer to Risk Management Plan included in the Project Management Plan [R-2]

Part H: Post Implementation Review (PIR) Plan

Type of PIR Report	Target In-Service or Completion Date	Target PIR Completion Date
Simplified PIR	2022-12-30	2023-05-08

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Replacement of 40 Standard Stacking Frames with Long Stacking Frames in West IFB	Currently there are 40 Standard Stacking Frames in the West IFB	40 Standard Stacking Frames replaced with Long Stacking Frames in West IFB	Addition of 40 Long Stacking Frames in the West IFB	Fuel Handling Engineering
Replacement of 30 Standard Stacking Frames with Long Stacking Frames in East IFB	Currently there are 30 Standard Stacking Frames in the West IFB	30 Standard Stacking Frames replaced with Long Stacking Frames in West IFB	Addition of 30 Long Stacking Frames in the East IFB	Fuel Handling Engineering

Part I: Definitions and Acronyms

BCS- Business Case Summary
CPAA- Chestnut Park Accord Assignment
DSC- Dry Fuel Storage Container
ECC- Engineering Change Control
EFFAA- East Fuelling Facilities Auxiliary Areas
EPC- Engineer Procure Construct (Contract Type)
ES MSA- Extended Services Master Service Agreement
FFAA- Fuelling Facilities Auxiliary Areas
I/F- Irradiated Fuel
IFB- Irradiate Fuel Bay
IMS- Inspection & Maintenance Services
LSF- Long Stacking Frame
NWMD- Nuclease Waste Management Division
PWU- Powers Worker Union
PSA- Purchased Services Agreement
SF- Stacking Frame
SSF- Standard Stacking Frame
WFFAA- West Fuelling Facilities Auxiliary Areas

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

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Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

For Internal Project Cost Control

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Appendix A: Summary of Estimate										
Project Number:	16-80067 16-80067									
Project Title:	DN IFB Stacking Frame Replacement (Long Bundle): DN IFB Stacking Frame Replacement (Long Bundle)									
k$	**LTD**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Future**	**Total**	**%**
OPG Project Management	0	7	110	135	114	110	110	348	934	3
OPG Engineering (including Design)	0	6	25	25	25	25	25	83	214	1
OPG Procured Materials	0	0	504	504	504	504	504	1,512	4,032	12
OPG Station Support	[redacted]									
EPC Contract(s)										
Interest										
Subtotal										
Contingency										
Total	**0**	**30**	**4,279**	**4,346**	**4,056**	**3,963**	**3,963**	**12,326**	**32,963**	**100**

Notes			
Project Start Date	2014-01-13	**Total Definition cost** (excludes unspent contingency for Nuclear)	[redacted]
Target In-Service (or AFS) Date	2022-12-31	**Contingency included in this BCS** (Nuclear only)	
Target Completion Date	2023-06-30	**Total contingency released plus contingency in this BCS** (Nuclear only)	
Escalation Rate	3%	**Total released plus this BCS without contingency** (Nuclear only)	
Interest Rate	N/A (OM&A)	**Total released plus this BCS with contingency** (Nuclear only)	$0 k
Removal Costs	$0 k	**Estimate at Completion** (includes only spent contingency for Nuclear)	[redacted]

Prepared by:	**Approved by:**
Umar Rizwan Sr. Technical Officer Design Projects Darlington 19-Nov-2014. Date	Ricardo Fiorini Section Manager Design Projects Darlington 19-Nov-2014 Date

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Appendix B: Comparison of Total Project Estimates and Project Variance Analysis

Comparison of Total Project Estimates

Phase	Release	Approval Date	Total Project Estimate in k$ (by year including contingency)						Future	Total Project Estimate
			2014	2015	2016	2017	2018	2019		
Execution	Partial	Nov 2014	30	4,279	4,346	4,056	3,963	3,963	12,326	32,963

Project Variance Analysis

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management	0	0	934	N/A	
OPG Engineering (including Design)	0	0	214	N/A	
OPG Procured Materials	0	0	4,032	N/A	
[redacted]					
Total	**0**	**0**	**32,963**	N/A	

Type 3 Business Case Summary

Project #: 16-80067
Document #: D-BCS-35361-10001 R00
Project Title: DN IFB Stacking Frame Replacement (Long Bundle), <Partial> <Execution> Release

Appendix C: Financial Evaluation Assumptions

Key assumptions used in the financial model of the Project are (complete relevant assumptions only):

Project Cost:

1. OPG will procure 70 Long Stacking Frames (Cat ID: 497180) and will deliver to site for installation by the contractor. The cost of the LSFs is budgeted in the project cost.
2. OPG will also procure ~ 210 standard waste bins (Cat ID: 490723) for the disposal of the SSFs. The cost of Standard Waste Bins is budgeted in the project cost.
3. OPG internal cost estimate was developed in house and covers both phases of the project.

Financial:

1. Rates used for OPG resources do not include escalation past 2015. Therefore a [redacted] escalation rate per year is considered and is included as specific contingency. The same [redacted] rate of escalation per year used for other costs (material, contract)

Project Life:

1. The replacement of the Standard Stacking Frames is expected to take 8 Years. The SF replacement work will start at the end of Q2 of 2015 and will end at the end of 2022. The project close-out will be completed by June 30, 2023.

Energy Production:

1. N/A

Operating Cost:

1. N/A

Other:

1. N/A

List further detail below as appropriate from the Financial Evaluation:

N/A

Appendix D: References

1. D-PCH-35361-10001 "Replacement and Disposal of Standard Stacking Frames with long Stacking Frames in E & W FFAA Fuel Bays"
2. D-PLAN-35361-0512286 " Project Management Plan- DN IFB Stacking Frame Replacement (Long Bundle)"
3. NK38-SOW-35361-10001 " Scope of Work Document- Replacement and Disposal of Standard Stacking Frames with long Stacking Frames in E & W FFAA Fuel Bays"

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit F2
Tab 3
Schedule 3
Table 1

Table 1
OM&A Project Listing - Nuclear
Projects ≥ $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project No.	Category	Start Date	Final Completion Date	Total Project Cost[2] (M$)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M)	2013 Actual ($M)	2014 Actual ($M)	2015 Actual ($M)	2016 Budget ($M)	2017 Plan ($M)	2018 Plan ($M)	2019 Plan ($M)	2020 Plan ($M)	2021 Plan ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
		ONGOING PROJECTS FROM EB-2013-0321																	
1	DN	Primary Heat Transport Liquid Relief Valve Modifications	38933	Regulatory	Dec-08	Jul-24	25.8	13.2	0.0	0.0	1.8	1.9	2.3	0.0	0.2	3.7	0.0	0.0	0.0
2	ENG	Fuel Channel Life Management	62444	Sustaining	Aug-09	Jun-16	54.1	0.0	54.1	0.0	9.2	8.3	2.3	0.4	0.0	0.0	0.0	0.0	0.0
3	PN	Locking Tabs - Boiler Divider Plate (Pickering 1 & Pickering 4)	49248	Sustaining	Jun-07	Dec-18	23.9	14.4	0.0	0.0	(0.6)	0.3	(0.0)	0.0	0.0	8.2	0.0	0.0	0.0
4	ENG	Fuel Channel Life Extension	80014	Value Enhancing	Nov-13	Jun-18	105.8	41.2	0.0	0.0	0.0	4.9	10.0	15.6	12.3	0.7	0.0	0.0	0.0
5		**Subtotal**					209.5												
		COMPLETED PROJECTS FROM EB-2013-0321																	
6	DN	DN EQ Component Replacements	38457	Regulatory	Oct-04	Jun-14	59.9	0.0	63.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	ENG	Probabilistic Risk Assessment Upgrade	62440	Regulatory	Jan-09	Jun-14	50.1	0.0	51.1	0.0	8.8	4.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
8	PN	PB Steam Generator Locking Tab Replacement	40641	Sustaining	Mar-07	Sep-12	35.2	0.0	20.5	39.4	(0.2)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9		**Subtotal**					145.2												
		PROJECTS NOT IN EB-2013-0321																	
10	DN	Irradiated Fuel Bay Stacking Frame Replacement	80067	Sustaining	Dec-14	Dec-22	33.0	9.4	0.0	0.0	0.0	0.0	2.5	3.5	3.3	3.2	3.2	0.0	0.0
11		**Subtotal**					33.0												

Notes:
1 Projects with expenditures during Test Period AND Completed/Deferred Projects (from EB-2013-0321 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Numbers may not add due to rounding.

Table 2a
OM&A Project Listing - Nuclear
Projects $5M - $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost[2] ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		ONGOING PROJECTS FROM EB-2013-0321						
1	DN	DN OH180 Aging Management/Support Program	34011	Sustaining	Design and qualify replacement circuit boards, power supplies and other components to replenish inventory and eventually replace obsolete components in the OH180 programmable logic controllers.	Dec-08	Dec-17	5.1
2	DN	DN Capping of D2O Collection Lines	38419	Sustaining	Cap D2O leakage collection lines on all four units downstream of Pressure & Inventory Control system valves to stop any significant leakage flow to the Primary Heat Transport D2O Collection tank .	Dec-11	Oct-19	8.4
3	ENG	Power Operated Valve Program, N-PROC-MA-0092, Recovery	62447	Sustaining	Update power operated valve program to address deficiencies and complete outstanding work.	Jul-11	Dec-15	6.9
4	ENG	Severe Accident Management Guidelines (SAMG) Implementation Improvements	62449	Regulatory	Improve the OPG Severe Accident Management program and ensure related CNSC Fukushima Action Items are completed.	Mar-12	Jun-16	19.5
5	ENG	DCC Aging Management	62553	Sustaining	Participate in CANDU Owners' Group joint project to manage the aging of digital control computers vital to the operation of the units.	Mar-04	Aug-18	14.5
6	IMS	Inspection Qualification	66105	Regulatory	Demonstrate compliance with the Canadian Standards Association Standard N285.4 Periodic Inspection of CANDU Nuclear Power Plant Components by proving a systematic and well-documented approach to non-destructive examination qualification.	Nov-06	Dec-17	15.3
7	PN	PB DCC Obsolescence	40505	Sustaining	Upgrade display hardware, replace necessary components, and procure critical spares.	Aug-03	Dec-15	5.9
8	PN	PB Boiler Blowdown Pipe Support Improvements	40683	Sustaining	Install new and/or modified piping supports at selected locations in the Reactor Auxiliary Bay and Screenhouse to make the Boiler Blowdown system more robust.	Oct-10	Jun-15	11.1
9	PN	PA Fuel Handling SPV Equipment Reliability Improvement Project - OM&A	46635	Sustaining	Refurbish fuel handling equipment that present single points of vulnerability for reliable operation.	Jan-00	Jan-00	7.0
10		**Subtotal**						**93.6**
		DEFERRED/COMPLETED PROJECTS FROM EB-2013-0321						
11	DN	Boiler Water Lancing (Future campaigns)	38450	Sustaining	Remove deposits from secondary side the Steam Generators to prevent under-deposit corrosion.	Apr-07	Sep-12	9.4
12	DN	DN Modified 37 Element Fuel Bundle	38936	Sustaining	Develop and qualify modified fuel bundle to address heat transport aging effects and prevent derating of Darlington.	Jan-09	Sep-14	6.0
13	DN	DN SG Gas Generator and Power Turbine Overhaul	38324	Sustaining	Complete overhaul and refurbishment of the Standby Generators.	Dec-06	Dec-11	7.1
14	ENG	Cyber Security	62442	Regulatory	Security Protected	Apr-09	May-14	5.1
15	PN	PB U8 Moderator Annubar Retrieval	40547	Sustaining	Locate and retrieve flow measurement primary element that broke off during commissioning that may cause failure of moderator piping.	Jan-10	Feb-16	5.3
16	PN	Pickering B Life Expired Building Demolition	25010	Sustaining	Demolish buildings outside of the Protected Area that are past their expected life and are no longer in use (Fire Code requirement)	May-11	Deferred	8.8
17	PN	NPT Fire Safety Assessment Upgrades	26003	Regulatory	Update fire safety assessments to comply with Canadian Standards Association Standard N293-07 Fire Protection for CANDU Nuclear Power Plants.	Aug-09	Jan-13	8.5
18		**Subtotal**						**50.2**

Table continues on Ex. D2-3-3 Table 2b

Notes:
1 Projects with expenditures during Test Period AND Completed/Deferred Projects (from EB-2013-0321 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Numbers may not add due to rounding.

Table 2b
OM&A Project Listing - Nuclear
Projects $5M - $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project No.	Category	Project Description	Start Date	Final Completion Date	Total Project Cost[2] ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		PROJECTS NOT IN EB-2013-0321						
19	DN	DN Boiler Blowdown Piping Refurbishment	31506	Sustaining	Redesign Boiler Blowdown System piping and supports based on dynamic load analysis to address significant vibration and pipe movement arising from steam/water hammer and thermal shock during intermittent blowdown operations.	Dec-12	May-19	17.8
20	DN	DN GFP Sample Delay and Alternative PHT Sampling Point	31514	Sustaining	Modify the sample lines of the Gaseous Fission Product (GFP) Monitoring system to ensure adequate Heat Transport System (HTS) sample delay in order to correct a legacy design deficiency discovered during commissioning of the new system and allow the GFP Monitoring system to function within its design requirements; and □ provide an alternate HTS sampling point.	Dec-12	May-18	8.5
21	DN	DN EPG2 Gas Producer Engine Replacement	38323	Regulatory	Refurbish Emergency Power Generator 2, which condition assessments have shown to have a degraded gas generator and power turbine.	Oct-12	Dec-18	20.0
22	DN	DN Reduced HTS Pressure-Temperature Envelope Modifications	80016	Regulatory	Implement modifications necessary to meet the revised pressure-temperature envelope during cooldown arising from results of the Fuel Channel Life Management project.	Jan-14	Dec-26	11.7
23	DN	DN RD-310 Implementation - Safety Analysis Improvement	80028	Regulatory	Upgrade the Darlington Safety Report to meet the requirements of CNSC Regulatory Document REGDOC-2.4.1 Deterministic Safety Analysis (formerly RD-310 Safety Analysis for Nuclear Power Plants).	Jul-14	Dec-20	9.0
24	DN	DN Phase 2 Station Battery Replacement (50310, 50390)	80062	Sustaining	Replace lead-calcium Class 1 and Emergency Power System battery banks that are approaching their end of service life.	Jan-15	Dec-19	13.8
25	DN	DN New Heat Transport Pump Seals	80071	Sustaining	Install new design Heat Transport Pump seals that address the operating deficiencies and poor reliability of the existing seals.	Dec-14	Oct-19	13.8
26	DN	DN Aging Management	80079	Sustaining	Fund a dedicated team initially for 2 years at station to strategize and manage the aging management scope in collaboration with Station and Refurbishment stakeholders and eventually manage these issues into Darlington station business plan.	Nov-14	Dec-17	8.2
27	DN	DN Aging Management Scope Defining Inspections	80110	Sustaining	Support execution of inspection activities to better define the aging management scope is support of the updated Integrated Implementation Plan.	Feb-15	Dec-18	9.9
28	DN	DN X-750 Spacer Retrieval	80112	Regulatory	Retrieve 24 spacers, intact, from all four axial locations of six selected channels, for material surveillance as mandated by OPG's established plan for maintaining Inconel X-750 annulus spacer fitness-for-service and, thereby, allow the Darlington units to operate to their planned service lives in advance of their respective refurbishments.	Mar-15	Nov-18	13.6
29	ENG	Fukushima Oversight Project	62448	Regulatory	Fund a dedicated project oversight team to interface with regulatory and nuclear industry agencies, manage regulatory actions, identify and initiate projects, and provide high level monitoring for successful completion of the Fukushima Response regulatory commitments and project portfolio.	Dec-11	Jun-16	7.4
30	ENG	Nuclear Fleet Safety Systems Functional Assessment	80072	Regulatory	Perform functional assessments of the Backup Safety Systems to assure they are capable of performing their functions required by design and licensing basis and that testing is adequate to demonstrate reliable safety functions.	Apr-14	Sep-17	10.0
31	PN	PN Instrumentation & Control Obsolescence	41024	Sustaining	Specify and qualify replacement instrumentation and control devices to replace obsolete components in a number of different systems.	Dec-12	Nov-18	9.3
32	PN	PA PHT D2O Storage Tank Pressure Control Improvement	49234	Sustaining	Improve control of the Pickering A Primary Heat Transport D2O Storage Tank cover gas pressure during reactor cooldown by increasing helium make-up rate.	Nov-11	May-16	5.7
33	PN	PN Equipment Reliability Initiatives	80060	Sustaining	Address selected equipment and/or system degradation to ensure improvement in forced loss rate.	Feb-14	Dec-18	19.5
34	PN	PN Fuel Channel Life Assurance	80157	Value Enhancing	Preserve the option of operating Pickering beyond its present planned service life of December 2020 by funding a number of technical assessments and implementation of strategies to manage fuel channel fitness for service past December 2020.	Sep-15	Dec-17	9.1
35	PN	PA LP Feed Heater Tube Bundle Degradation	82839	Sustaining	Replace low-pressure feedwater heaters in Units 1 and 4 that are exhibited tube degradation due to chemical attack and are at or approaching the tube plugging limits.	Sep-15	Apr-18	15.2
36		**Subtotal**						**202.5**
37		**Total**						**346.3**

Notes:
1 Projects with expenditures during Test Period AND Completed/Deferred Projects (from EB-2013-0321 or subsequent).
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

Numbers may not add due to rounding.

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**	1	2.1	2.1
2	**Pickering NGS**	0	0.0	0.0
3	**Nuclear Support Divisions[2]**	1	0.9	0.9
4	**Total**	2	3.0	1.5

Notes:
1 Projects with expenditures during Test Period.
2 This project is for Security & Emergency Services.

Table 4
OM&A Project Listing - Nuclear
Portfolio Projects (Unallocated)[1]

Line No.	Project Name	Category	Potential Start Date
	(a)	(b)	(c)
	Darlington NGS		
1	DN Life Expired Building Demolition Projects	Sustaining	2016 or later
2	DN Revenue Metering Upgrades	Regulatory	2016 or later
3	DN Burnish Mark Interaction and Fuel Gap Mitigation	Sustaining	2016 or later
4	DN Feeder and Fuel Channel Baseline Inspections	Regulatory	2016 or later
5	DN Powerhouse Ventilation Fire Damper Replacement	Regulatory	2016 or later
6	DN Backdraft Damper Refurbishment	Sustaining	2016 or later
	Pickering NGS		
7	PN Scanning Tool for Elongation Measurement Improvement	Sustaining	2016 or later
8	PN Fire Alarm Display Computer Replacement	Sustaining	2016 or later
9	PA Fuel Handling Conveyor Stop Cylinder Replacement	Sustaining	2016 or later
10	PA Smart Positioner Installation	Sustaining	2016 or later
11	PA Standby Generator Fuel Forwarding Electrical System Upgrade	Sustaining	2016 or later
12	PA Condenser Air Extraction Pump Replacement	Sustaining	2016 or later
13	PN Flow-Assisted Corrosion Mitigation Strategy	Sustaining	2016 or later
14	PN P58 Buried Blowdown Piping Replacement	Sustaining	2016 or later
	Nuclear Engineering		
15	Condition-Based Maintenance Programme Implementation	Value Enhancing	2016 or later
16	Power Operated Valve Modifications	Sustaining	2016 or later
17	Alternate Fuel Channel Deformation Analysis Development	Sustaining	2016 or later
18	Microbiologically Induced Corrosion Chemistry Control and Sampling	Sustaining	2016 or later
	Inspection and Maintenance Services		
19	IMS Fuel Channel Scrape Tooling Modifications	Regulatory	2016 or later

Notes:
1 Projects with potential expenditures during Test Period. Each project is forecast to have a project expenditure of less than $20M.

Table 5
OM&A Projects - Nuclear Operations
Listing of Business Case Summaries Filed

Line No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date	Project Stage	BCS Status	BCS Status in EB-2013-0321
	(a)	(b)	(c)	(d)	(e)	(f)
		ONGOING PROJECTS FROM EB-2013-0321				
1	38933	Primary Heat Transport Liquid Relief Valve Modifications	Feb-14	Execution	Partial	Partial
2	62444	Fuel Channel Life Management	Oct-12	Execution	Full	Partial
3	49248	Locking Tabs - Boiler Divider Plate (Pickering 1 & Pickering 4)	Dec-11	Execution	Partial	Partial
4	80014	Fuel Channel Life Extension	Nov-13	Execution	Partial	N/A
		COMPLETED PROJECTS FROM EB-2013-0321				
5	38457	DN EQ Component Replacements	Jan-08	Complete	Full	Full
6	62440	Probabilistic Risk Assessment Upgrade	Apr-12	Complete	Full	Full
7	40641	PB Steam Generator Locking Tab Replacement	Dec-10	Complete	Superceding	Superceding
		PROJECTS NOT IN EB-2013-0321				
8	80067	Irradiated Fuel Bay Stacking Frame Replacement	Dec-14	Execution	Partial	N/A