ONTARIO POWER GENERATION

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December 22, 2016

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0152 – Updated Interrogatory Responses

Enclosed are amendments to five OPG interrogatory responses. OPG has submitted these documents through the Regulatory Electronic Submissions System and is providing twelve (12) paper copies. This material will also be available on OPG's website at www.opg.com. Attachment 1 is a table listing the amended exhibits.

A description of the amended material is provided below:

Exhibit	Description of the Change
L-1.2-5 CCC-8	Attachment 3 – The completed Niagara Tunnel Project Post Implement Review is provided as Attachment 3
L-4.3-1 Staff-72	Page 8 – Provides internal audit plan for 2017-2019 in relation to the Darlington Refurbishment Program
L-6.5-7 ED-27	Part a) and Attachment 2 - An electronic spreadsheet underlying OPG's economic assessment of Pickering Continued Operations is provided.
L-6.10-1 Staff-189	Page 2 – Numerical: Provides the updated estimate of 2017-2021 SR&ED ITCs
L-11.1-15 SEC-95	Page 1-2 – Provides the regulated hydroelectric capital projects expected to be fully or partially in service between 2017 and 2021 for which incremental revenue requirement is expected to be included in the CRVA and total regulated hydroelectric in-service additions for the 2017-2021 period.

Yours truly,

[Original signed by]

Barbara Reuber

cc: Carlton Mathias (OPG) via e-mail
Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail

ATTACHMENT 1 - TABLE OF EVIDENCE AMENDMENTS

EXHIBIT	TAB	SCHEDULE	ATTACHMENT	TITLE	FILED (F) UPDATED (U)	DATE
L	1.2	5	3	CCC-008	U1	2016-12-22
L	4.3	1		Staff-72	U1	2016-12-22
L	6.5	7	2	ED-27	U1	2016-12-22
L	6.10	1		Staff-189	U1	2016-12-22
L	11.1	15		SEC-095	U1	2016-11-10

CCC Interrogatory #8

Issue Number: 1.2
Issue: Are OPG's economic and business planning assumptions that impact the nuclear facilities appropriate?

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 4, p. 3
With respect to OPG's asset management and project review process there is reference to the post implementation review process (PIR) which is an appraisal process designed to evaluate whether planned results of a given investment have been met following completion. It further states that the two main objectives of the PIR process are to verify whether the benefits stated in the project business case were realized, and to capture the lessons learned from each project so they can be applied to improve future projects and other investment decisions.

a. Please provide an example of a PIR that followed a simplified format and one that followed a comprehensive format;

b. Was a PIR undertaken for the Niagara Tunnel Project? If not why not? If so, please provide it;

c. How many projects are subject to a PIR appraisal each year?

Response

a. Attachment 1 provides an example of a Post Implementation Review (PIR) that followed a simplified format. Attachment 2 (which contains confidential content as marked) provides an example of a PIR that followed a comprehensive format.

b. Yes. The PIR for the Niagara Tunnel Project is provided in Attachment 3.

c. On average over 2014 to 2015, OPG's nuclear business conducted about 20 PIRs per year.

Simplified Post Implementation review

Station:	Project Name:	Project No.:	Units:	Controlled Doc No.:
Pickering B	Standby Generator Governor Upgrades	13-49109	056, 078	NK30-PIR-54600-00004

Approval	Cost	Date
Original Approval Estimate	$21,680K	Mar 2006
Approval Revision Estimate		
Final Approval Estimate	$22,872K	Mar 2007
Final Actual Project Cost	$22,751K	Jan 2015

Timing	
Target Date	Dec 2007
Latest Approved i/s Date For all 6 SG's	Jun 2008
In Service Date with modification of all 6SG's	Aug 2008
Period used to calculate Performance result	Jan-2009 to Jun-2015

BRIEF DESCRIPTION OF PROJECT

This project is one of the initiatives for SG upgrades designed to reduce the likelihood of a forced outage due to obsolescence and parts unavailability that has been negatively impacting reliability. Prior to the start of the initiative, Pickering B SG performance was showing deteriorating trend. Design basis start reliability targets were not met. Approximately 70% of the total SG trips were identified due to deficiency of SG start up controls & permissive issues. Continued degradation would have potentially caused severe, protracted adverse impact on SG performance that would led to forced unit outages due to unavailability of Standby Class III power redundancy. Objective of the project is to improve start reliability as per Design Basis, reduce failures and increase availability & reliability of Standby generators.

BCS Recommendations:

A total of $22,872,000 was recommended for release to complete final installation of the Standby generator governor Upgrade project by June 2008.

This project is designed to reduce the likelihood of a forced outage due to obsolescence of SG controls and spare parts unavailability that has been negatively impacting reliability. Scope of the project is based on Pratt & Whitney report IMR#510 issued in the year 1999 which focused on equipment obsolescence issues and OEM's inability to support critical products.

This project is one component of the REGM 28007285 committed to CNSC.

Scope for Project# 13-49109

-Governor fuel delivery system replacement
-New PLC based integrated governor and sequencer controls
-Replace majority of the relay based start/control logic with PLC
-Independent over speed protection system
-PLC based speed switches and timers
-New data event logger with expansion facilities
-New Machine Monitor – Temperature & Vibration

Financial:

Project# 49109 came $121,000 under budget.

DELIVERABLES	
Target	**Achievement**
Measurable Parameter: Available For Service (first 2 SG's) Targeted Results: AFS and Open Items acceptance by stakeholders How it will be measured: Attach copy of AFS and Open Items	Available for service dates for first 2 SG's are as below:- 1.056-54600-SG3: AFS date 13-Oct-2006 Attachments: i) Copy of AFS report as per N-FORM-10091 ii) OPEN items as per AR# 28070181; Current status: Complete 2.078-54600-SG3: AFS Date 22-Dec-2006 Attachments: i) Copy of AFS report as per N-FORM-10091 ii) OPEN items as per AR# 28073103; Current status: Complete **Note**: - All 6 SG's have been completed with modification; last SG was completed on 15-Aug-2008. Supporting data has been provided for first 2 SG's only as per deliverables per BCS. Available for service dates for remaining SG's:- 3.056-54600-SG1: AFS date 20-Jul-2007 4.078-54600-SG1: AFS Date 22-Oct-2007 5.056-54600-SG2: AFS date 28-Dec-2007 6.078-54600-SG2: AFS Date 15-Aug-2008
Measurable Parameter: SG Machine performance criteria met Targeted Results: Commissioning results acceptance by Design How it will be measured: Signed commissioning report scanned in Passport	SG Machine performance criteria were met and commissioning results accepted by Project Design for all 6 SG's. Signed commissioning reports are in ASSET SUITE. Details of commissioning reports for first 2 SG's are as below:- 1. NK30-CR-54600-00034: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG3 – Cover page attached. 2. NK30-CR-54600-00038: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG3 – Cover page attached. Commissioning reports for remaining SG's are as below:- 3. NK30-CR-54600-00042: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG1. 4. NK30-CR-54600-00043: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG1. 5. NK30-CR-54600-00047: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG2. 6. NK30-CR-54600-00051: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG2.

Measurable Parameter: Standby Generator System Health Targeted Results: Removal of SG Governor and associated control system as contributor to RED system Status How it will be measured: Updated SG system Health report indicating improved status for affected equipment	Overall U058 SG System Health is consistently 'WHITE" since Jan-2009 till to date. Copy of Cover page of Health Report is attached for the year 2009 (Jan- Jun) and for the year 2015 (Jan-Jun).
Measurable Parameter: REGM #28007285 complete Targeted SG Governor Project contribution to REGM completion How it will be measured: SMB REGM schedule review milestone added to SG outage plan	SG Governor Project contribution to REGM AR# 28007285 completed on 15-Aug-2008. Memo NK30-CORR-00531-04903 sent to CNSC on 29-Aug-2008 providing status update on completion of Standby Generator Upgrade Project – Copy attached.

QUALITATIVE RESULTS	
Health & safety	No health & safety incidents were reported during the project.
Lower maintenance costs	Governor and logic failures minimized due to installation of upgraded PLC based system and new components.
Diagnostic capabilities	Improved diagnostic capabilities using new data logger and machine monitor, thus reducing trouble shooting time. Also, it eliminated the need for Maintenance/Eng to be present for every test run.
Reduction in CM/DM backlogs	Replacement of obsolete system with PLC based system resulted in reduction in CM/DM backlog for governor control components.
KEY LESSONS	
Spare parts for upgraded Governor controls	1. Lifetime spare parts are not adequate considering rate of failure in the last 6 years of operation Current Status: Review of lifetime spares completed in consultation with Plant Design - Complete 2. Vendor Taken off ASL while the parts were in transit, resulted in quartine of parts. Current Status: Team has been engaged for pursuing balance parts as detailed under "Follow up actions".

Variable Frequency Drive	Variable frequency drive terminal block rating was incorrect for the application. Current status: Replacement terminal blocks installed on all 6 SG's.
Annunciator Panel	Frequent annunciator lock up occurred on all SGs resulted in OPS memo. Current Status: New annunciator Panel installed on all 6 SGs
Vibration cards	Initially installed vibration cards were not suitable for high temperature application for Turbine end. Current Status: Vibration cards replaced for high temp application.
HP Fuel pump recirculation Solenoid valve	Sticking of solenoid valve: SG Start up failures due to sticking of solenoid valve (Failed closed) in the Fuel pump bypass line. Current Status: Design review completed and Software Modification installed.
FOLLOW-UP ACTIONS	
Spare parts for upgraded Governor controls	Spare parts team comprising of members from Perf Eng, Plant Design, Procurement Eng and Supply Chain is working on getting lifetime spares on shelf. Current status: Out of total of 188 spares, 173 spares are on hand, PO has been placed for 5 items and remaining 10 items are in progress. Status of spares is tracked at PHC dashboard bi-weekly

Prepared by: N Kumar Date: 18-NOV-2015

Naresh Kumar
SE, Standby Generators

Reviewed by: M. Knutson for Date: Nov 27, 2015

Dean Townsend
Director- Station Eng

Approved by: Carlo Crozzoli Date: 21 Dec 15

~~Beth Summers~~ Carlo Crozzoli
Interim SVP and Chief Financial officer

Approved by: Date: 5 Jan 15

Jeff Lyash
President & CEO

Attachments:-

1. Copy of BCS for Pickering B Standby Generator Upgrade project 13-49109
2. Project Closure Report
3. Copy of Letter to CNSC, ref# NK30-CORR-00531-04903 dated August 29, 2008
4. Completion of REGM AR#28007285
5. Available for service, Open item list and Commissioning reports for 056-SG3 & 078-SG3
6. Cover page of System Health Report

ONTARIO POWER GENERATION

Report

Internal Use Only Commercially Sensitive	
Document Number: D-PIR-63578-10001	Usage Classification: N/A
Sheet Number: N/A	Revision: R001

Title:
FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW

Fuel Handling Power Track Capital Improvement Project (16-31438) - Comprehensive Post Implementation Review

D-PIR-63578-10001-R001
2013-04-29

Order Number: N/A
Other Reference Number:

Internal Use Only
Commercially Sensitive

Prepared by: 29-APR-2013
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S. Wong – Investment Planning

Reviewed by: 30 April 2013
Steve Ramjist Date
Director of Operations and Maintenance
Darlington

Reviewed by: May 1/2013
Brian Duncan Date
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Darlington

Approved by: June 14/13
Donn Hanbidge Date
Chief Financial Officer

Approved by: 13-06-18
Tom Mitchell Date
President and CEO

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Revision Summary

Revision Number	Date	Comments
R000	2013-03-27	Initial issue.
R001	2013-04-29	Added management note to executive summary.

Preface

Contributions and Acknowledgments

The CPIR team interviewed the following people and their contribution to the review is much appreciated.

Terry Acheson
Mario Campigotto
Brian Duncan
Paul Mather
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The CPIR Team

Bill Barron
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Executive Summary

A unique design feature of CANDU reactors is that they allow for online fuelling operations. This is accomplished through the reliable operation of the fuel handling systems. Darlington has 3 pairs of fuelling machine heads capable of fuelling all 4 units. The fuelling machine heads are delivered to the units using any one of three trolley pairs. In 2004 a power track roller failed, detached from the system, and became entrained in the power track chain. The entangled roller halted motion of the power track and caused extensive damage to the supporting steel work. The resulting recovery, repair work, and production losses cost the company $45 M (SCR D-2004-00642).

As a result of the root cause analysis of the 2004 event, the Fuelling Machine Power Track Rehabilitation Project 16-38451 was initiated which included a comprehensive list of OM&A and capital funded initiatives. The first initiatives to be undertaken included a risk assessment, cable chain replacement and flat bar re-welding. In March of 2006, modifications and maintenance improvement related scope items, including the detection and surveillance systems, were removed from this project and split into two new projects (16-31438 and 16-38472).

The proposed scope of the Fuel Handling Power Track (FHPT) Capital Improvement Project (16-31438) included a dynamic instrumentation system (DI), a dropped roller detection system (DRD) and an enhanced video surveillance system (VSS). In the end only VSS was completed for a total cost of $16.12 M.

The project approval authority called for a Comprehensive Post-Implementation Review (CPIR) of project 16-31438 due to dropped scope, $3.35 M in capital cost write-offs to OM&A, cost increases and schedule delays. An independent CPIR team was formed in January of 2013 to conduct a review of the project as per the CPIR Terms of Reference (see Appendix A).

The FHPT Capital Improvement project was successful in terms of cost and schedule when compared only to the Phase 2 Full Release Business Case Summary (BCS) approved in 2010. A surveillance system has been put in place, which allows remote inspection and real-time monitoring of the FHPT. However, not all VSS cameras are fully functional and outstanding actions still exist.

When looking back at the project, the CPIR team concluded that overall cost performance was not acceptable and scope management and implementation during the project was not well executed. The Partial Release BCS approved in late 2007 forecasted the final project cost to be $9.3 M and included three modifications (DI, DRD and VSS). The Phase 1 Full Release BCS approved in early 2009 forecasted the final cost of the project to be $17.38 M for the three modifications. In mid 2009, five years after the initial event, OPG requested a project scope assessment from the Original Equipment Manufacturer (OEM). The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

For project 16-31438, the problem definition and business need statement of improving FHPT reliability was very general leading to several initiatives. The business need did not focus on the

root causes determined during the 2004 event investigation. Also, no initial value engineering or third party assessment was done on the identified alternatives.

The relationship between initiatives under the various FHPT projects was not fully understood or managed. The increased FHPT reliability due to roller endplate replacements reduced the overall risk and this was first mentioned in the partial release BCS for project 16-31438 in 2007. This was an early indication that some planned initiatives might no longer be needed but no reassessment was done.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of the project. This was a result of the OEM assessment leading to a joint review by Fuel Handling and Design Projects. The joint review determined that there was low value for money in proceeding with DI and DRD.

Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.

The Phase 2 Full Release BCS in 2010 forecasted the final cost of the project to be $16.16 M, which is approximately $1 M less than the previous BCS, but the scope of the project had been reduced to the VSS modification.

A major challenge for this project was the unpredictable installation schedule. Installation required the use of No Fuel Windows (NFWs). The project installation work did not have priority status for NFWs and committed NFWs had a tendency to move. The missed NFWs added substantial cost to the project when contractors were placed on standby. Through teamwork and communication between the projects organization and the station later in the project, Fuel Handling mini outages were used to complete the installation.

The CPIR team conducted a thorough assessment of project management practices, BCS quality and project outcomes. Project documentation was reviewed and project stakeholder interviews were conducted. Lessons learned have been summarized in Section 6 of this report. Recommendations based on the key themes of the lessons learned have been documented in Section 7 and are summarized below.

Recommendation 1: Fuel Handling Mini Outages bring Predictability to Project Installation Schedules

The CPIR team recommends that the use of FH mini outages with committed dates be explored as an alternative to the use of NFWs for project installation work. NFWs have a tendency to move and competing station priorities may result in bumped project work. Resources can then be assigned to project installation work with more certainty, increasing the probability of achieving project schedule and cost estimates.

Recommendation 2: Milestones and Other Time Pressures should not take priority over Project Management Best Practices

The CPIR team recommends that project management best practices should not be sacrificed to meet deadlines. Milestones should not be declared complete when actions to meet the milestone are still outstanding.

Recommendation 3: Major projects resulting from High Profile Events should undergo an Initial Independent Assessment of the Business Need and Identified Alternatives

The CPIR team recommends that a third party assessment be done early in projects resulting from high profile events. After a major station event, emotions are running high and there is an urgency to quickly correct the identified causes. An independent assessment of the proposed solutions would help identify if those solutions are feasible, if they meet the business need and whether the alternative analysis has been thorough including comprehensive stakeholder involvement.

Recommendation 4: Clear and Specific Problem Definition and Business Need Statement need to be developed at the beginning of a project

The CPIR team recommends that extra scrutiny be placed on the problem definition and business need statement at the outset of the project lifecycle. A clear and specific problem definition linked to root causes is crucial to enable a thorough alternative analysis, scope identification and scope prioritization. All activities throughout the project lifecycle should be continuously checked against the business need to ensure continuity with the problem definition and proposed solution.

Recommendation 5: An approved Project Execution Plan is needed early in the Project Lifecycle

The CPIR team recommends that a thorough project execution plan be prepared and approved during the early stages of a project. A plan should be in place to document, monitor and control all project management knowledge areas to ensure effective project execution.

Recommendation 6: Alternatives to Sole Source Contracts should always be explored

The CPIR team recommends that the justification for sole source work be closely scrutinized to ensure that benefits from the competitive bidding process are not lost. GE was chosen as the sole source for the camera system on the basis of their experience with fuel handling technology. There was no technical basis for this decision, as the surveillance system technology is not dependant on any unique aspects of the fuel handling system technology.

Recommendation 7: An improved Document Repository and Versioning System is required

Having a proper document control system for working documents is useful for tracking changes and ensuring documentation is not lost. Documentation was lost at various stages of the project. Lost documentation leads to rework and loss of information crucial to decision making. Asset Suite and shared drives are not an effective means of managing working documents.

Management Note:

Darlington Station management and Projects and Modifications management have reviewed the recommendations in this report and concur with the recommendations. It was noted that some actions have already been implemented to address aspects of these recommendations. Where actions have not yet been implemented, the Action Tracking process will be used to open new actions, assign owners and track these actions to completion.

1.0 INTRODUCTION

Darlington nuclear generation station is a 4 unit CANDU plant that first went into service in 1990. It provides a total output of approximately 3,500 MWe which is enough to serve the power needs of two million people. A unique design feature of CANDU reactors is that they require online fuelling operations. Reliable operation of the reactors requires reliable fuel handling systems.

Darlington has 3 pairs of fuelling machine heads capable of fuelling all 4 units. The fuelling machine heads are delivered to the units using any one of three trolley pairs. In 2004 a power track roller failed, detached from the system, and became entrained in the power track chain. The entangled roller halted motion of the power track and caused extensive damage to the supporting steel work. The resulting recovery, repair work, and production losses cost the company $45 M (SCR D-2004-00642).

The Fuel Handling Power Track (FHPT) Capital Improvement Project (16-31438) was a result of the root cause analysis following up from the 2004 event. The proposed scope included a dynamic instrumentation system (DI), a dropped roller detection system (DRD) and an enhanced video surveillance system (VSS). In the end only VSS was completed for a total cost of $16.12 M.

The project approval authority called for a Comprehensive Post-Implementation Review (CPIR) of the project due to the material scope change during the execution phase, $3.35 M cost write-off, cost increases and schedule delays.

An independent CPIR team was formed in January of 2013 to conduct a review of the project. As stated in the CPIR Terms of Reference (see Appendix A), the purpose of a CPIR is as follows:

- Verify the achievement of planned benefits identified in the business case and capture any other quantitative and qualitative outcomes of the investment.
- Assess the effectiveness of the project's intent, project charter, project execution plan, project execution, and operational performance results in meeting the business needs and the investment objectives stated in the BCS of the project.
- Review the appropriateness of risk management from business case approval through project completion and document lessons learned in different aspects of risk management including identification, analysis, mitigation plan, and monitoring and control throughout the life of the project.
- Review the effectiveness or quality of the BCS of the project looking back from results to provide feedback for future decisions. The financial evaluation used in the BCS should be re-assessed using actual results and documented in completed PIRs.

The intent of the CPIR is to complete a “cradle to grave” assessment of the project in order to identify lessons learned and recommendations. The report is not written to lay blame but rather to learn from past experience and allow OPG to improve its business management processes going forward. It is much easier to identify early warning signs after a project has been completed.

The CPIR team reviewed project documentation including documentation of other related fuel handling projects. Stakeholder interviews were conducted to fill in information gaps and to gain an understanding of how the project progressed. The team analyzed all the gathered information in order to produce the final report.

The CPIR report provides information consistent with the deliverables outlined in the terms of reference. Section 2 describes the project background and the overall project lifecycle. Sections 3 through 5 provide an assessment of business case summaries, project management related areas and project outcomes. Sections 6 and 7 summarize the lessons learned, conclusions and recommendations.

2.0 PROJECT BACKGROUND

2.1 Project History and Rationale

On January 21st, 2004 at about 16:00 hours, the Darlington FHPT system experienced a functional failure (SCR D-2004-00642 [R-13]). Intermediate roller #11 suffered a mechanical failure and had fallen into the lower cable pan becoming foreign material. The PT guide roller drum ran over the failed intermediate roller and broke free of its mounting. The guide roller drum shaft projected to the south of the main roller drum and began to interfere with supporting steelwork, halting motion of the FHPT system.

The failure caused significant damage to the Trolley (1,2 Power Track system, resulting in a 21 day outage of Unit 2 and a de-rating of Unit 1 to 59% for 15 days. The cost of the failure was estimated at $45 M in lost revenues.

The root cause investigation on SCR D-2004-00642 was completed on March 16th, 2004. The SCR states that roller #11, a blind roller that could only be inspected at one to two years intervals, was missed when reinforced type rollers were installed in all blind roller positions around the end of 2001. The SCR also states that there is strong evidence that the last scheduled inspection identified serious damage on roller #11.

The Incident Investigation Report for SCR D-2004-00642 states that the root causes of the event were:

1. Management failed to recognize the magnitude of the risk associated with operating degraded equipment (Power Track), to properly assess the risk and to follow up on indications of major risks (from SCRs, Health Reports etc.) (Management Direction - Personnel exhibited insufficient awareness of the impact of actions on nuclear safety or reliability)

2. Station Management failed to apply adequate priority to corrective actions initiated to resolve persistent problems with the Power Track (Corrective Action - Response to a known or repetitive problem was untimely)

   Contributing Cause #1: Inadequate commitment to the Corrective Action program on the part of FH Management (Management Direction - Inadequate commitment to program)

   Contributing Cause #2: The design of the reinforced rollers for the Power Track does not meet Station requirements.

SCR D-2004-00642 had a total of 9 assignments (2 to 10). Assignments 2 and 3 were for the design and procurement of replacement rollers to address the immediate issue of failed rollers. Assignment 4 was to determine the feasibility of minor modifications to prevent rollers from failing on the power track. Assignments 5 to 7 addressed changes to corrective action planning in light of the event. Assignment 8 was an extension of a TOE action in order to complete Assignment 9.

Assignment 9 and 10 dealt with the long-term corrective action plan. Assignment 9 was to conduct failure analysis and risk assessment. Assignment 10 was to identify initiatives that would reduce the high risk of failure of the FHPT system.

Following the 2004 FHPT T(1,2 incident, temporary PT inspection cameras were installed as temporary modifications (TMOD) in the PT stationary support frame and on trolleys T(3,4 and T(5,6 to cover off the inspection of blind rollers. The temporary installed trolley cameras were obsolete and no spares were available. These TMODs remained in place until they were replaced with permanent equipment.

2.2 Project Initiation and Planning

2.2.1 Project 16-38451 Fuelling Machine Power Track Rehabilitation

2.2.1.1 Project Charter

In September of 2004 the project charter for the FHPT rehabilitation project 16-38451 [R-01] was issued. This project originally covered all FHPT project work resulting from the January 2004 event investigation. The project need was to improve FHPT reliability and performance and included three major scope areas:

1. System Analysis Work
2. Fuelling Machine Power Track Modifications.
3. Fuelling Machine Power Track Maintenance

Item 1 included a FHPT risk assessment and a study of FHPT dynamics. Item 2 included a number of modifications including the design and installation of a FHPT failure detection system and system surveillance enhancement. Items 1 and 2 were to be managed by Darlington Design projects while item 3 was to be managed by the Fuel Handling organization.

2.2.1.2 2004 Risk Assessment

The DNGS FHPT Risk Assessment P0440/RP/005 [R-14] was issued in November of 2004. The risk assessment analyzed initiating events (usually a component failure) and subsequent events and actions leading to PT failures that could impact trolley motion and fuel cooling. Importance measure quantification analysis was carried out on the subsequent actions to determine the risk reduction worth and risk achievement worth. This determines how sensitive the overall risk value is to the probability of an action or event. It was determined that the most important future event to consider was the failure to detect a guide roller sub-component failure. The dominant contributor (25%) was an event similar to the one described in SCR D-2004-00642 but with irradiated fuel on board. The assessment concluded that the public risk was negligible.

The Risk Assessment concluded that the financial risk associated with all potential power track failures was estimated to be $17 M per year and was substantial. The report warranted exploring the benefits/costs of potential improvements to reduce the risk and preventative maintenance efforts focussed on minimizing roller failures.

A list of initiatives was developed to address the risk of FHPT failure. The Risk Assessment results were used as the rationale behind the need to reduce risk.

2.2.1.3 Project 16-38451 Scope and Releases

The original estimates for project 16-38451 indicated that all packages would be available for service (AFS) by the end of 2007 for a cost of $12 M, including $0.95 M for the detection and surveillance system. General Electric (GE) was indicated as the design agency and would complete the design packages for all aspects of the project.

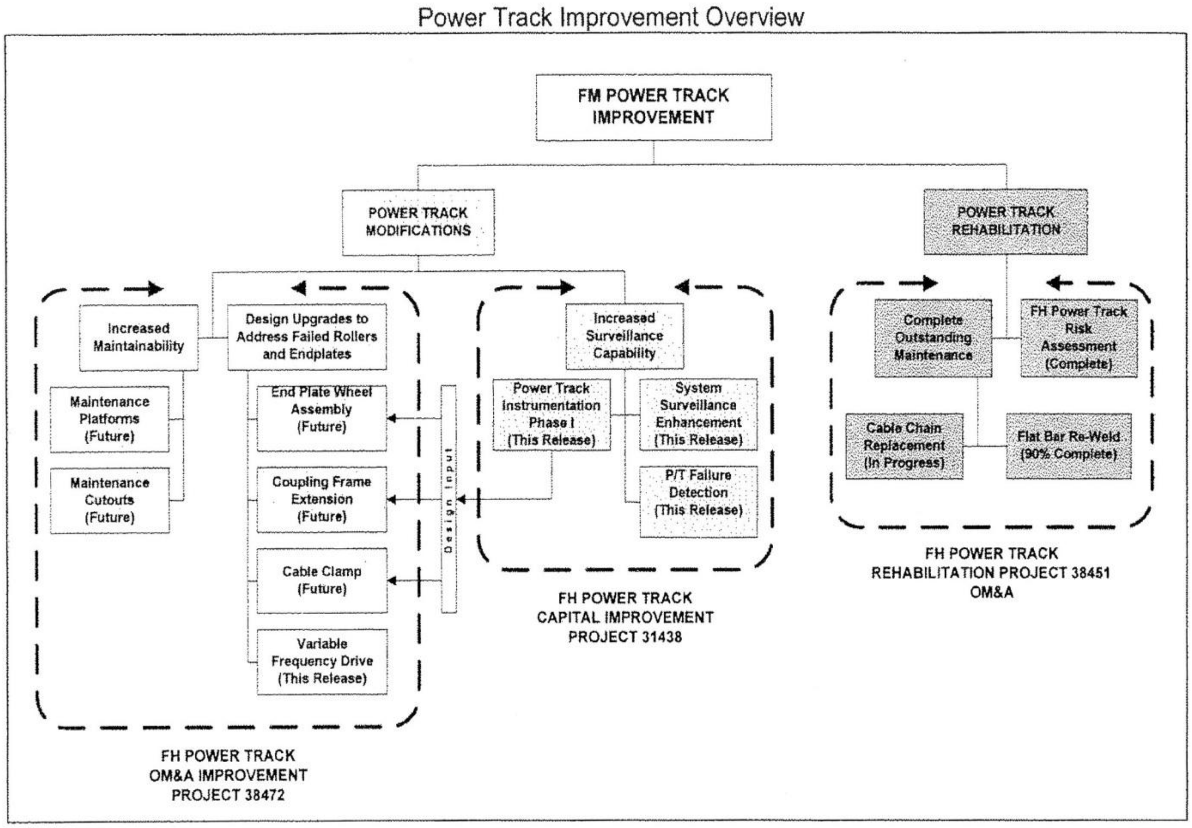
In March of 2006 a full release business case summary for project 16-38451 [R-02] was approved for a total of $7.90 M for this project. Modifications and maintenance improvement related scope items, including the detection and surveillance systems, were removed from this project and split into two new projects (16-31438 and 16-38472). At this point in time, no money had been spent on the detection and surveillance system items.

Project 16-38451 was closed out on May 2nd, 2008 for a total cost of $6.74 M as per the project closure report [R-03].

2.2.1.4 Status of FHPT Rehabilitation and Improvement Projects at Year End 2007

The following schematic provides an overview of the re-aligned FHPT-related project scopes at the end of 2007:

Figure 2.1: Overview of Fuelling Machine Power Track Improvement initiatives in late 2007



2.2.2 Project 16-31438: Fuel Handling Power Track Improvement (Capital)

In April of 2006 the project charter for the FHPT Improvement Capital Funded Project 16-31438 [R-04] was issued. The project need was to improve the reliability and performance of the Darlington FHPT by implementing the required modifications. The objectives were:

1. Design and installation of a Dynamic Instrumentation System (DI)

   DI would be a permanent instrumentation system to monitor dynamics, vibrations and forces acting upon the FHPT system and to provide early detection of component failure.

2. Design and installation of a Surveillance System (VSS)

   VSS would replace a number of temporary cameras and provide remote coverage of 100% of the critical FHPT components to aid in failure detection.

3. Design and installation of a Failure Detection System (DRD)

Dropped Roller Detection (DRD) would provide immediate and responsive indication of significant intermediate roller failures.

The AFS for all work packages was estimated to be December of 2008 for an estimated total of $2.88 M.

2.3 Project Execution

On May 28th, 2007 the initial developmental business base summary (BCS) [R-05] for preliminary engineering of DRD and DI and to pursue alternatives for VSS was approved for $1.38 M. This BCS covered two FH projects (16-31438 and 16-38472) which were the result of the scope splitting from the original FHPT rehabilitation project (16-38451). The total estimated cost for both projects was $16.98 M of which $10.94 M was estimated for the capital project. Installation was being targeted for the 2009 vacuum building outage (VBO). It was proposed that General Electric (GE) would be the sole-source design agency for all aspects of the project except for the VSS portion. Other options for VSS enhancement were being pursued at this time due to high estimates received from GE.

On November 13th, 2007 a partial BCS [R-06] was approved for $4.40 M to commence design activities. This BCS also covered both the OM&A and capital projects. The total estimated cost for both projects was $14.28 M with $9.29 M for the capital portion. Preliminary engineering was in progress for all modifications except for VSS which was under negotiations for the design portion of the work. VBO installation was still being targeted at this time. FH Technical had now assumed the roles of Modification Team Leader (MTL) and Field Team Leader (FTL) for the VSS portion of the project.

On January 26th, 2009 a full release BCS [R-07] for phase 1 was approved for a further $8.53 M to complete detailed design, installation and closeout of the remaining VSS releases (release 2, 3 & 4) and DI. This BCS was to also fund a DRD trial to determine feasibility and to determine if a phase 2 release will be required for DRD installation and closeout. This BCS covered only the capital project and the new estimated total was $17.38 M. Some VSS work was injected into the VBO window and the rest was to be done using the online process.

In August of 2009 the Original Equipment Manufacturer (OEM), KabelSchlepp, issued an assessment [R-10] of the FHPT. The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M [R-09] was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of the OEM assessment [R-10] leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

On July 29th, 2010 the phase 2 full release BCS [R-08] was approved for an additional $1.83 M for the completion of the VSS for a final total of $16.16 M. This BCS covers the remaining design, procurement, installation, commissioning and closeout of VSS. Previous releases covered the design of the first 3 VSS releases and the materials and installations of releases 1 and 2. The increased cost is attributed to schedule delays and higher than estimated costs associated with design, procurement and pre-installation activities. The BCS states that a Comprehensive Post Implementation Review was now required.

2.4 Project Closure

The FHPT capital improvement project was declared available for service through operations acceptance on November 30th, 2011. There were 59 outstanding action tracking items related to the project at the time of AFS (see Appendix B). Refer to section 5.0 for details regarding cameras that have failed and still require repair.

The project closure report [R-11] was issued on November 2nd, 2012. The final actual cost was $16.12 M which was lower than the phase 2 full release estimate of $16.16 M which included [redacted] of contingency. The project closure date was October 31st, 2012 which is one month earlier than forecasted.

A project Lessons Learned document [R-12] was issued on January 16th, 2013 shortly after the CPIR process began. The CPIR report will be prepared by the end of March 2013, thus closing the loop on the entire project. These were deliverables mentioned in the phase 1 full release and to be completed under the phase 2 work but the project was closed before their completion.

The related project for FHPT OM&A improvements, Project 16-38472, was closed out on October 11th, 2012 for a total cost of $2.13 M. The completed scope of work included installing strain relief on the moving and fixed ends of the 3 trolley pairs and installing soft starting devices on the 3 trolley motors.

2.5 Project Life Cycle

The time line for project 16-31438 is summarized in Figure 2.2, below, in the context of the overall FHPT improvement initiatives. The project charter was issued in April 2006, with final reduced scope of VSS enhancements going into service by November 2011.

Figure 2.2: Basic Timeline for Darlington FHPT Projects and Related Events

Jan-04	FHPT Event

	Rehab OM&A Improv. Project 38451
Sep-04	38451 Project Charter • project scope: (a) system analysis work, (b) 9 FH PT modifications (mods) & (c) FH PT mtce
Nov-04	NSS Risk Assessment completed
Mar-06	38451 BCS - Project Full release

	Capital Improv. Project 31438		OM&A Improv. Project 38472
Apr-06	31438 Project Charter	Apr-06	38472 Project Charter
May-07	31438 BCS - Developmental release	May-07	38472 BCS - Developmental release
Nov-07	31438 BCS - Partial release	Nov-07	38472 BCS - Partial release
Jan-09	31438 BCS - Full release Phase 1		
Aug-09	OEM Assessment of FHPT cable condition		
Nov-09	31438 OM&A Cost Write-off		
		May-10	38472 BCS - Full release
Jul-10	31438 BCS - Full release Phase 2		
Nov-11	31438 Report of Equip. In-service		
		Oct-12	38472 Project Closure
Nov-12	31438 Project Closure		

3.0 BUSINESS CASE SUMMARY ASSESSMENT

3.1 Project Releases

A business case summary (BCS) provides a concise outline of the information required by the approval authority to release a specific level of funding needed to achieve specific results in terms of scope, schedule and costs, with an understanding of the associated risks. BCSs are often prepared as a project proceeds through the project gates between project phases such as the initiation phase, definition phase and execution phase.

A summary of the project releases for project 16-31438 is provided in Table 3.1:

Table 3.1: Summary of Capital Improvement Releases

Date	Capital Project Release			Total Capital Project	
	Type	Amount	Scope	Estimated Cost	Full Scope
May-07	Developmental	$1.4M	• preliminary engineering for DRD & DI • pursue alternatives for VSS design	$10.943M listing estimate (+100% to -50%)]: - [redacted]	VSS, DRD, DI
Nov-07	Partial	$4.4M	• scope: complete design of DI, DRD & VSS PMODS • prepare for installn (2009 VBO)	$9.3M [conceptual estimate (+60% to -25%)]: - [redacted]	VSS, DRD, DI
Jan-09	Full release Phase 1	$8.5M	• install VSS release (rel) 2 during VBO; design/install VSS rel 3 & 4; commission VSS [AFS Sept 2010] • procure/ install/ commission DI [AFS July 2011] • install DRD pilot with full implemtn in next release • train Ops&Mtce & Perf Eng staff • revise Ops Mtce procedures	$17.4M [release quality estimate +15%/-10%]: - [redacted]	VSS, DI, pilot DRD
Jul-10	Full release Phase 2	$1.8M	• VSS going ahead; DRD and DI cancelled - previous release: Design of VSS rel 1, 2 &3; matl purchase & install of VSS rel 1&2 - this release: design VSS rel 4; matl purchase & install of VSS rel 3 &4; commission VSS • project closeout	$16.2M [release quality estimate +15%/-10%]: - [redacted]	VSS
Nov-12	Project Closure			• final cost : $16.1M	VSS

3.2 Alternative Analysis

The Alternatives presented in the Nov. 2007 partial release BCS included the following capital improvement scope:

- Base Case: Do nothing beyond the short term reliability measures pursued under project 16-38451
- Alternative 1: Install the VSS enhancements, DI & DRD (recommended)
- Alternative 2: Delay the VSS enhancements, DRD & DI for 2 years
- Alternative 3: Install the DRD only
- Alternative 4: Install the VSS enhancements only
- Alternative 5: Install the DI only

The reason given for not pursuing Alternative 4 was that it “would not address reliability and may not detect a dropped roller in time to prevent damage”.

In the January 2009 phase 1 full release BCS, Alternative 1 had changed to recommending a phased implementation of the DRD system instead of its full implementation. The same reasons as in the 2007 partial release BCS were given for not recommending Alternative 4. The Base Case stated that although there had been significant improvements to the PT including weld repairs, endplate roller replacements & increased maintenance which may improve overall reliability, the underlying causes of PT failure still continued to exist and needed to be better understood for long term reliability.

During 2009, an assessment of the FH PT cable condition was conducted by the OEM. It became evident that more critical system health issues (cable degradation, chain wear) affecting reliable operation of the PT needed to be implemented over the proposed monitoring systems (DI, DRD).

In the July 2010 phase 2 full release BCS, the recommended alternative changed to completing installation of the VSS enhancements and dropping the DI & DRD scope altogether. Reasons for installing the VSS enhancements included that the current temporary VSS was unreliable and had component obsolescence issues and, as such, might reduce station availability of each FM pair and might leave PT failures undetected.

3.2.1 Lessons Learned

LL 3.2.1: At the start of a project, the problem definition and Business Need statement should be defined in the most specific terms possible, allowing specific solutions to be identified and prioritized based on the expected benefit attributable to each solution.

LL 3.2.2: A thorough review of the alternatives should be conducted in the early project phases (initiation phase, early definition phase) to review their implementation practicality and requirements, including the cost and schedule requirements. The evaluation of the alternatives should involve all stakeholders (design, operations, maintenance, OEM, etc.) and should consider the project-specific constraints such as the limited availability of No Fuel Windows in this case.

3.3 Estimate Accuracy

The project estimates developed during the various project releases are summarized in Table 3.1. The estimates including contingencies for the full project scope of VSS, DI & DRD were as follows:

- $10.9 M in May 2007 (developmental release) including [redacted]% contingency
- $9.3 M in November 2007 (partial release) including [redacted]% contingency
- $17.4 M in January 2009 (full release phase 1) including [redacted]% contingency

The phase 1 full release BCS had a release quality estimate (+15%/-10%) prepared after extensive front end planning including input from a third party estimator. The increased cost was partly due to the planned installation of most of the VSS equipment using the online process and not during the 2009 VBO.

In November 2009, a $3,347 K write-off was made for the DI and DRD scopes of work. The write-off resulted from an assessment of the PT cable condition by the OEM in mid 2009, followed by a joint review by Design Projects and Fuel Handling, which determined these initiatives to be low value for money because more critical system health issues (cable degradation and chain wear) needed to be addressed.

The DI and DRD initiatives were not proven technology and did not have a history of use in similar systems and, as such, carried more risk in terms of their design, implementation and value.

In the end, the project cost was $16.1 M for the installed VSS alone. Assuming the VSS scope was 1/3 of the estimated total project cost of $17.4 M in the phase 1 full release BCS, this represents an increase from $6 M to $16 M of the VSS system costs from January 2009 to July 2010. Cost increases were due to schedule delays and higher that estimated design, procurement and installation support costs. It was during this time that the DI and DRD were dropped from scope.

3.4 NPV Evaluation

For the developmental, partial and phase 1 full release business cases, the Base Case assumption was that the cost to OPG of doing nothing was $17 M/yr. This cost comes from the 2004 FHPT risk assessment report which assessed a financial risk of $17 M/yr to OPG for all the potential events leading to power track failures that could impact trolley motion and/or fuel cooling. The 2004 risk assessment was based on an event tree methodology used in OPG reactor risk assessments. When the FH PT Improvement program was initiated after the 2004 incident, the $17 M/yr financial risk to OPG was the financial risk being addressed by undertaking all the scopes of work included in projects 16-38451, 16-31438 and 16-38472. In other words, it was determined that these were the scopes of work which would prevent “all potential events leading to power track failures that could impact trolley motion and/or fuel cooling”.

However, as time progressed, and project 16-38451 scope was completed, the financial risk of doing nothing, or $17 M/yr, was not reduced by the contribution of the completed project 16-38451 scope of work towards reducing this risk. The developmental and partial releases for projects 16-38472 and 16-31438 and even the phase 1 full release for 16-31438 continued to use the full $17 M/yr financial risk in the base case in calculating the present value to OPG of the Base Case. This likely overstated the potential benefit to OPG of pursing the scopes of work proposed in these releases.

It should be noted that this was a sustaining project and as such, a positive net present value to OPG is not a requirement for the recommended alternative to proceed. The net present value of an alternative is calculated by subtracting the present value (PV) of the Base Case from the PV of the alternative. It is important that the inputs and assumptions used in the PV calculations of the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.

The challenge in re-evaluating the NPV calculation for project 16-38472 is in determining a realistic valuation of the financial risk to OPG of not pursuing this specific scope of work. For the 2010 phase 2 full release BCS, it was determined that the annual financial risk to OPG of not proceeding with the VSS enhancements was the following:

- major failure of guide roller or subcomponent with irradiated fuel on board and cooling maintained resulting in a 2 unit 60 day outage to recover [3.6% probability]
- failure of guide roller or subcomponent with no irradiated fuel on board resulting in a 1.5 unit 30 day outage to recover [7.5% probability]
- major failure of guide roller or subcomponent with irradiated fuel on board and cooling failure [0.2% probability]

Given that the final cost of the project was close to the cost estimate included in the phase 2 full release BCS, the re-evaluation of the NPV calculations in that BCS would yield the same results.

3.4.1 Lessons Learned

LL 3.4.1: When several major scopes of work are associated with reducing a financial risk to the company, the outstanding (remaining) financial risk used in the financial evaluation in successive business cases should be revised to reflect the outstanding (non-retired) portion of the financial risk, as appropriate.

LL 3.4.2: It is important that the inputs and assumptions used in the financial evaluations, or NPV calculations, for the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.

3.5 Deliverables

The 2010 phase 2 full release BCS for project 16-31438 stated the project would provide the following deliverables:

- In service declaration of VSS releases 2 & 3 by Aug 2011
- In service declaration of VSS releases 4 by Nov 2011
- VSS providing 100% visual coverage of the PT area
- Upgraded VSS will improve roller visibility and overall PT coverage to facilitate Operations and Engineering with current observation and inspection practices
- Qualitative factors:
    - Improved operator and engineering visibility of PT components without entering containment (lower radiation doses)
    - Improved reliability of VSS reducing trolley out of service caused by camera failures
- CPIR completed by November 2012 including evaluation of the stated measurable parameters listed in Table 3.5
- Key lessons learned documented in a project Close-out Lessons Learned Report.
- Project closeout

The deliverables in the 2009 phase 1 full release BCS for project 16-31438 also included training for Operations, Maintenance and Performance Engineering staff on the new systems as well as new and/or revised Operating and Maintenance procedures.

4.0 PROJECT MANAGEMENT ASSESSMENT

4.1 Project Charter

4.1.1 Overview

The project charter for project 16-31438 [R-04] was issued in April of 2006. The stated business need was to improve the reliability and performance of the Darlington FHPT. The objective was to permit safe and long term reliable operation by implementing DI, DRD and VSS. The proposed project close out milestone was December 2008 and the estimated cost was set at $2.88 M. GE was mentioned as the agency to be used to provide technical and design support.

4.1.2 Lessons Learned

LL 4.1.1: Project charters should not identify the specific solutions including specifying the design agency to be used for the proposed modifications. Other options should be pursued rather than jumping to a sole-sourcing design solution that could be more costly than other options.

LL 4.1.2: The problem definition and business need statement should be as clear and specific as possible from the beginning of the project. In this case it is very general and it is difficult to relate the proposed solutions to the business need. A general problem statement leads to scope development and prioritization issues later in the project lifecycle.

4.2 Project Execution Plan

4.2.1 Overview

As per N-PROC-AS-0039 (superseded) every project must have an approved Project Execution Plan (PEP) to monitor and control the project. The PEP should be prepared during the definition phase and before the execution phase of the project.

The only approved PEP for project 16-31438 [R-15] was prepared in December of 2009 and approved in February of 2010. This PEP addressed VSS release 3 and 4. An earlier PEP was prepared in 2008 to address DI, DRD and VSS but was lost and never approved. The preparer had prepared the PEP prior to leaving on rotation. The staff preparing the PEP in 2009 were not aware of the original PEP.

The BCSs made reference to proposed PEP approval dates but these documents were never produced and approved. A PEP was approved after DI and DRD were dropped from scope and was developed in parallel with the final BCS (see Table 4.1).

Table 4.1: Proposed vs Actual PEP Approval Dates

BCS	Proposed PEP Approval Date	Actual PEP Approval Date
Developmental	Dec 2007	No PEP
Partial	Aug 2008	No PEP
Full Phase 1	Feb 2009	No PEP
Full Phase 2	No Proposed Date	Feb 2010

4.2.2 PEP Quality

The following documents were prepared and approved under the PEP:

1. Basis of Estimates
2. Summary of Cash Flow
3. Risk Management Plan
4. Resource Management Plan
5. Schedule P5
6. Quality Management Plan

The Contract Management Plan was developed as a separate document.

The following missing documents from this PEP should have been included to make it effective:

1. Scope Management Plan
2. Schedule Management Plan
3. Cost Management Plan
4. Communication Management Plan

4.2.3 Lessons Learned

LL 4.2.1: Project Execution Plans (PEP) should be developed in parallel with the BCS. The PEP helps document, monitor and control various key project management areas. The BCS should be a summary of much of the information outlined in the PEP.

LL 4.2.2: Project Execution Plans should contain plans for all project management areas. Project 16-31438 had many scope, cost and schedule management issues. The existence of a proper PEP could have helped mitigate the risks.

LL 4.2.3: Proper turnover and document management processes need to be followed for OPG projects to ensure no loss of information. A PEP was developed in 2008 but was lost and never approved. Information from this PEP could not be used for the development of the actual approved PEP.

4.3 Scope Management

4.3.1 Scope Identification

Assignment 10 from SCR D-2004-00642 was to identify initiatives to reduce FHPT risks. Stakeholders involved with the project described it as an emotionally driven project and described the process as a “shotgun” approach where a large number of initiatives were quickly identified to attempt to improve FHPT reliability.

The problem definition and need statement of improving FHPT reliability was very general leading to a wide range of initiatives. No initial value engineering or third party assessment was done to ensure the identified initiatives met the business need. The business need also didn’t address the root causes determined during the 2004 event investigation.

The scope of FHPT Capital Improvement project (16-31438) was originally covered under the FHPT Rehabilitation project (16-38451), which started in 2004. At that time all 12 FHPT initiatives identified as a result of the 2004 PT event were considered under the same project. Due to the number of project initiatives, a large number of work packages were not being progressed in a timely manner.

By April of 2006 no progress had been made with a number of work packages including DI, DRD and VSS. They were removed from the scope of project 16-38451 in order to start two new projects, 16-31438 and 16-38472. DI, DRD and VSS make up the scope of project 16-31438 (see Figure 2.1).

4.3.2 Scope Reduction

In December of 2009, DI and DRD were cancelled due to a number of contributing factors:

- New information from a third party (OEM) assessment [R-10] recommended taking a different approach to preventing/mitigating failures in the FHPT. These were covered under project 16-38472.
- In service experience with the new Generation III roller endplates had proved they have a longer life than the previous versions.
- Uncertainties in the availability of installation and commissioning windows and the associated costs of the DRD and DI systems.

There was a $3.35 M write off due to the dropped scope of this project.

The DI portion of the project was intended to provide information necessary to carry out a number of initiatives under project 16-38472 which was being executed in parallel. With the cancellation of DI, a number of these initiatives were also de-scoped.

4.3.3 Scope Management Quality

Under the Scope Management Plan, scope should have been identified, agreed upon and managed as per Project Management Procedures. There was no formal Scope Management Plan prepared for this project.

The initial scope didn't undergo a third party assessment to ensure the initiatives were feasible and actually met the business need. Scope prioritization was not effective as numerous initiatives under the original project (16-38451) were not progressed for the first two years.

The relationship between initiatives under the various FHPT projects was not fully understood or managed. The increased FHPT reliability due to roller endplate replacements reduced the overall risk and this was first mentioned in the partial release BCS for project 16-31438 [R-06] in 2007. This was an early indication that some planned initiatives might no longer be needed but no reassessment was done.

4.3.4 Lessons Learned

LL 4.3.1: Projects with multiple initiatives need to have their scope prioritized to ensure effort is being focused on key areas and areas that need to be completed before others can begin. A Scope Management Plan could have helped document the relationship between initiatives and help prioritize the larger number of initiatives.

LL 4.3.2: Projects consisting of a large number of initiatives should be grouped into a number of separate projects based on the business need and objective they are trying to achieve. This would allow the proper amount of resources to be assigned to each project to ensure progress is being made on all initiatives.

LL 4.3.3: When multiple projects exist for a system, the impact of one project must be assessed on the other projects. Due to several parallel FHPT projects, one project's impact on other projects was not realized. After the roller endplate modification, the performance of the modification should have been assessed before starting the proposed modifications (DRD and DI system) on the same system.

LL 4.3.4: Projects should not contain initiatives requiring design input from the completion of another project. This was the case for project 16-38472, OM&A FHPT Improvement, as shown in figure 2.1. Those initiatives could also be a second phase of the preceding project, only to be executed based on the results of the design inputs. This would reduce effort and money spent on initiatives that were ultimately cancelled due to the cancellation of DI.

LL 4.3.5: Projects resulting from a major station event should initially be reviewed by a third party to ensure the initiatives are feasible and aligned with the stated business need. The OEM should be contacted immediately for input. Emotions tend to be running high after a significant event and an independent look at the proposed solutions should be completed. Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.

4.4 Schedule Management

4.4.1 Overview

In the early stages of project 16-31438 it was mentioned that the project modifications would target a 2009 VBO installation window. In the developmental BCS [R-05], VBO installation was the target and it was identified as a risk due to the time to complete the design and procure the materials. Successful implementation during the VBO would require vendor schedule concessions, prompt BCS approvals and relief from outage milestones. Proposals from GE were already acquired in order to expedite design completion. GE was eventually awarded a sole source contract in order to expedite the design because of their expertise with FH systems.

The VSS portion of the project was done in a phased approach with 4 releases. This allowed work to be grouped for a more structured installation and to capitalize on lessons learned from previous releases. VSS release 2 was eventually executed during the VBO in order to take advantage of the multi-unit outage to run cables. Other VSS releases were completed online using No Fuel Windows (NFW).

After the removal of DRD and DI from the project scope, only the VSS portion was executed. A formal schedule (P5) was prepared and accepted by key stakeholders for release 3 and 4, however a formal Schedule Management Plan was not prepared for this project. This schedule (P5) was prepared based on milestones committed to in the latest BCS.

4.4.2 Scheduling Challenges

The major schedule delays can be attributed to NFW unpredictability and changes to the Reactivity Management Plan. Equipment reliability issues would cause changes to the Reactivity Management Plan in order to ensure zone levels were maintained which, in turn, would result in NFW changes. The impracticality of using NFWs should have been identified earlier in order to determine a better path forward.

Another challenge was obtaining NFWs committed to VSS installation. This resulted from competing work priorities and insufficient communication between the projects organization and FH operations and maintenance. Multiple jobs could have been carried out during the same window but the various work groups believed they were in direct competition for the available time.

Some delays were also attributed to the time required to issue permits and obtain work authorization. Resources weren't adequate to handle the normal work load and the project work load simultaneously.

4.4.3 Scheduling Successes

In the later stages of the project, FH mini outages were used to get the project back on schedule. This was the first time use of such an outage and it proved to be an effective method of improving schedule performance. These outages were committed windows that were longer than regular NFWs which helped by reducing the overhead needed at the beginning of the window. This was made possible through increased communication and teamwork between various groups such as Projects and FH.

The final AFS milestone was achieved despite many scheduling challenges. This can be attributed to the mini outages and the schedule float that was added to mitigate the risk of installation window unpredictability.

4.4.4 Lessons Learned

LL 4.4.1: Time pressure should be avoided in order to follow project management best practices. Targeting VBO installation expedited the design phase of the project which resulted in the use of sole sourcing. This had an impact on overall project cost.

LL 4.4.2: Projects requiring field installation should attempt to have their schedule pre-negotiated and committed to by operations and maintenance. However, the use of NFWs for project installations is ineffective as these windows have a tendency to move and cannot be pre-negotiated.

LL 4.4.3: Fuel Handling projects requiring NFWs for installation, should explore the use of FH mini outages to complete the work. More work can be executed because of the reduction in overhead involved with starting work each time. The mini outages should be planned and committed to like a unit outage.

LL 4.4.4: Projects executed in areas with high radiation and limited accessibility should have adequate schedule float in order to meet installation milestones. Due to unexpected breakdown maintenance issues, most of the NFWs were taken away from this project.

LL 4.4.5: When executing project installation work, extra resources should be assigned for timely application of permits and work authorization.

4.5 Cost Management

4.5.1 Overview

The actual final project costs are outlined in table 4.2 and are in line with the approved phase 2 full release BCS including [redacted]. Costs were managed through assigning appropriate levels of contingency based on the quality of cost estimates (see Section 3.3). Some cost control measures included the use of competitive bidding for VSS release 4 and for the construction portion of the project. Contingency use and approvals were documented using the Project Change Request Authorization Forms (PCRAFs).

Table 4.2: Cost Summary

Cost Stream	Actual $k	Approved $k	Variance $k	Variance %
Project Management & Support	[redacted]			
Engineering				
Procurement				
Construction				
Interest				
Contingency				
Total	16,120	16,156	(36)	0.2

4.5.2 Cost Variance

The cost variance is summarized in table 4.2. Although there were some major variances, the overall actual costs were on target through the use of the approved contingency.

Project management costs were higher than expected due to the administration surrounding installation delays, coordinating schedules and resources, and providing technical troubleshooting. Engineering costs were lower because competitive bidding was done for the design of VSS release 4. Construction costs were nearly double the original estimate. This can be attributed to the unpredictability of the installation schedule. The reactivity management plan changed frequently due to equipment reliability issues resulting in the unpredictability of NFW availability. Costs also increased due to the required 24 hours/day support needed for the fuel handling mini outage that was eventually used for installation.

4.5.3 Cost Change Management

Cash flow changes were approved through the use of Project Change Request Authorization Forms (PCRAF). They outline the justification for the use of contingency throughout the project. Table 4.3 outlines all the PCRAFs associated with project 16-31483.

Table 4.3: Change Approval (PCRAFs)

PCRAF	Approval Date	Description of Change
001	Jun 19, 2008	Change of Labour Contract Award for DI Requesting contingency funding to cover installation Camera release 1, additional design costs for (DI,DRD, Cameras), project management, camera release 1

		installation, DRD installation and DI materials.
002	Sep 22, 2009	VSS Release 3 & 4 design schedule delayed Project contingency request, additional costs for design agency and installation for the VSS system.
003	Jan 05, 2010	Reduce 2009 control budget due to recommending cancellation of DRD and DI from scope.
004	Jan 15, 2011	Change in current approved cash flows; re-allocate budget from 2010 to 2011.
005	Apr 13, 2011	Additional funds for cost of fuel handling mini-outage installation. Restore previously returned funding from previous year.
006	Oct 13, 2011	Additional funding required for delays incurred through 2011 due to fuelling priorities.
007	Oct 31, 2011	Additional funding requested from contingency to cover incurred delays costs for 2011 installation due to fuelling priorities and other work programs.
008	Feb 03, 2012	Additional contingency funds required to cover closeout. Extra costs in 2011 resulted in lower available funds for 2012.

4.5.4 Cost Performance

Cost performance was tracked throughout the project and reported through monthly project updates. Cost performance is compared to the currently approved releases and PCRAFs which makes it difficult to use as a true indicator of overall project cost performance. This project went through a significant scope reduction and resulted in a cost write-off of $3.35 M and the project closure report still indicates a cost performance index (CPI) of 1.00.

The projected project cost nearly doubled in the phase 1 full release BCS in early 2009 (see Table 4.4). The decision to cut DI and DRD from the project scope took place later in 2009, after the design for both had been completed. Even with the massive scope reduction, the phase 2 full release BCS only projected the final cost to be $1.10 M less.

Table 4.4: BCS Release and Estimate Summary

BCS	Release Capital ($k)	Estimated Final Costs ($k)	Scope
Developmental	1,383	10,943	DI, DRD, VSS
Partial	4,417	9,285	DI, DRD, VSS
Full Phase 1	8,530	17,258	DI, DRD, VSS
Full Phase 2	1,826	16,156	VSS

4.5.5 Cost Write-Off

In August of 2009, 5 years after the initial event, the original equipment manufacturer (OEM) issued an assessment [R-10] of the FHPT. The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M [R-09] was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of the OEM assessment [R-10] leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

4.5.6 Lessons Learned

Many lessons learned affecting cost management can be found under other assessment areas.

LL 4.5.1: The CPIR team recommends that project cost performance for project closure reports should also show the deviation from the summary of estimate before contingency. CPI based on the most recently approved release is used for project cost management but the CPIR team feels that this does not give an accurate representation of overall cost performance looking back at a project.

4.6 Risk Management

4.6.1 Overview

The Risk Management Plan (RMP) was prepared under the PEP based on following procedures and governance:

1. Corporate Risk Management Policy – OPG-POL-0004
2. Corporate Risk Management Program and Guidelines – FIN-PROG-FM-001
3. Project Risk Management – N-INS-00120-10014

The RMP is prepared during the definition phase of BCS and should be part of the PEP. With the help of stakeholders, through brain storming, meetings and operating experience, all risks are identified and recorded in the Risk Register. Based on risks identified, contingencies in cost and float in schedule are included.

In the Risk Register, impacts and probabilities of risks were calculated. Response plans were prepared for every risk identified. This Risk Register was updated every month with current impacts, probabilities and response strategies. The latest Risk Register identifies 17 major risks.

[redacted]

Some of the major risks identified in the Risk Register, which could not be mitigated or avoided, are listed here:

1. Several NFWs or mini Outages were required to execute the field work, which were not easy to get. This risk was identified in the initial stage but could not be resolved in time.

2. The Risk Register identifies that permits and work authorization availability could become an issue. To mitigate it, there was some schedule float created in P5/P6 schedule but it was not resolved efficiently.

3. Due to limited field walk downs, most of the design was prepared based on assumptions and information/photos provided by Fuel Handling. This risk was identified and accepted in the Risk Register.

4. Coordination among many stakeholders was identified in the Risk Register but no formal strategy was prepared. Key stakeholders during installation were – three Design Agencies, Field Engineering (Electrical and Civil), OPG Design Team Lead (DTL), Modifications Team Lead (MTL), System Responsible Engineer (SRE), Operations and Maintenance (FH), Inspection and Maintenance Services (IMS), Supply Chain and Radiation Protection.

Some of the Risks which were not identified in the Risk Register during the initial stages of the project are listed here.

1. The 2009 VBO was a good opportunity to execute the field work. Management also planned accordingly but design and material were not ready. This sudden change in schedule was not identified in the Risk Register.

2. Project scope changed significantly just before the field execution commenced, which impacted cost significantly. The DRD and DI projects had been completely designed and material had been procured. Before installation began, both projects were dropped from the scope due to several reasons. This risk was not initially identified.

Despite several known and unknown risks, the project was completed with the allocated contingency in cost and float in the schedule.

4.6.2 Lessons Learned

LL 4.6.1: Risk Management Plans should be developed early in the project lifecycle in order to guide risk mitigation. Earlier identification of risks, such as schedule unpredictability, could have helped reduce the effect of these risks.

LL 4.6.2: Substantial effort should be spent on correctly identifying potential risks. Many major and foreseeable risks were not correctly identified which lead to cost, schedule and scope management issues. For example, the risk of not completing experimental work, such a DI and DRD, should be an identified risk in order to mitigate the effects of the scope reduction on other ongoing work.

4.7 Contract & Procurement Management

4.7.1 Overview

In the early stages of project 16-31438 it was identified that the project modifications would target a VBO installation window in 2009. This required expediting the design for DI, DRD and VSS which lead to a design agency sole source contract with GE. Sole sourcing was chosen because GE possessed FH system expertise, wiring drawings were controlled by GE and this was the most expeditious means of meeting the VBO installation window.

Later in the project, after the VBO window passed, a competitive bidding strategy was used for the design of VSS release 4. SNC-Lavalin was chosen as the design agency which resulted in significant cost savings. Having two different design agencies created some problems because they were both updating the same design documentation for overlapping design proponents for VSS release 3 and 4.

A competitive bidding process was used for the construction contractors. This resulted in EMC winning the contract for electrical installation and Black and McDonald winning the contract for civil work. A decision was made to use the same contractors for a number of releases due to the overhead involved with training and equipment familiarization.

4.7.2 Contract Management Plans

As Per FIN-MAN-CM-001, a Contract Management Plan (CMP) is required to record planning and post-award decisions that shall be used by OPG to monitor the contracts. It is both a communication and control tool. It can become a key factor in dispute and event resolution.

There were no CMPs prepared for VSS release 1 and release 2.

The following two CMPs were prepared as outlined in FIN-MAN-CM-001 for VSS release 3 and release 4 field installation work:

- CMP for Electrical Work performed under PO # 00195631
- CMP for Civil (Scaffold) Work performed under PO # 00176088

Under these two CMPs the following items were clearly identified:

- Scope of the Contracts, Contract Strategy, Responsibility Matrix (OHSA), Risk Management, Schedule and Communication Plan, Dispute Resolution, Acceptance Plan, Change Management, Payment plan

4.7.3 Lessons Learned

LL 4.7.1: A competitive bidding process should be used to avoid the costs associated with sole sourcing. If time pressures had not been present at the beginning of the VSS project, the use of competitive bidding could have resulted in significant cost savings.

LL 4.7.2: Projects containing multiple releases with overlapping design proponents should only use one design agency. If the releases don't contain completely independent designs, the same design agency should be used to avoid configuration management issues.

LL 4.7.3: Projects containing multiple releases should use the same construction contractor when possible. This reduces the overhead required for training and equipment familiarization.

4.8 Quality Management

A detailed Quality Management Plan was prepared under the PEP in compliance with CSA N286.2 standards.

Design Agencies complied with Design Agency Interface Agreement (DAIA) D-DAI-63578-0001 to produce the design packages.

All procurement activities were performed in accordance with N286.1-00 and as per N-PROC-MP-0098. Material which did not meet OPG requirements were documented and acted on as per OPG OSD&D process under N-PROC-MM-0021.

All Construction activities were performed in accordance with the requirement of CSA N286.3 program. Contractors performed construction work per approved OPG procedures and under OPG Certificate of Authorization. Online work scheduling process as outlined in N-PROC-MA-0022 were followed to schedule the work order tasks. Quality Surveillance of contractor work was conducted per N-PROC-AS-0074.

Inspection and Test Plans (ITP) were prepared and executed in field as per N-INS-01983.1-10001. All commissioning activities were performed by OPG Control Maintenance department as per CSA N286.4

4.9 Communication Management

There was no formal Communication Management Plan prepared. Regular meetings and teleconferences were organized throughout the project. These meetings were very useful in tracking the issues and resolving them in timely manner. Monthly project update reports were also prepared.

Regular and effective communication was attempted to coordinate with FH operations and maintenance to schedule the field work during No Fueling Windows (NFW). This communication improved in the later stages of the project which ultimately lead to the mini outages used to finish installations.

Meeting minutes and reports were originally saved but were eventually lost over time. This was discovered when CPIR interviewees attempted to retrieve this information.

4.9.1 Lessons Learned

LL 4.9.1: A communication management plan should be developed early in the project lifecycle. This would ensure the right people were receiving the right information at the right time. It would also help communication between other project teams working on the same system in parallel.

LL 4.9.2: Communication between the project team and station operations and maintenance is necessary to successfully complete field installations. Cooperation between the various stakeholders was necessary to get the schedule commitments.

LL 4.9.3: OPG needs a proper document repository and versioning system to accommodate working documents. Passport / Asset Suite and shared folders are not very useful in this area. This would help avoid the loss of important project documentation.

4.10 Resource Management

4.10.1 Project Organization

Resource management for this project became very challenging due to the lengthy project duration (2004 - 2012). The executing organization for the original project was Design Projects (DP). Resourcing issues resulted in no progress being made on a number of the original 12 initiatives between 2004 and 2006.

When project 16-31438 was started, the initial quotes from GE for the design of VSS were rejected because they were much higher than expected. At the end of 2007, the Fuel Handling organization took control of the MTL and FTL roles for the VSS scope of work.

At the time of the phase 2 full release BCS in early 2010, DP re-acquired the execution of the VSS work due to the soaring project costs. VSS was the only item remaining in the project scope. VSS release 1 and 2 were designed and installed. VSS release 3 design was done and installation planning was in progress. DP then went to a competitive bidding process for the design of VSS release 4. The contract was awarded to SNC-Lavalin while the previous 3 releases had been completed by GE.

The project manager, project leader and MTL roles were filled by DP throughout the project with the exception of the span of time FH provided the MTL for VSS. The DTL role was filled by Projects Design. The design agency was GE for DI, DRD and VSS releases 1, 2 and 3. SNC-Lavalin was the design agency for VSS release 4. No dedicated support was available from the work control department when permits and work authorization were needed for field execution.

FH project sponsors (SRE, operations and maintenance) should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.

Table 4.5: Project Executing Organization

Project	Time	DI	DRD	VSS
16-38451	2004-2006	DP	DP	DP
16-31438	Dev BCS (May 2007)	DP	DP	DP
	Partial BCS (Nov 2007)	DP	DP	FH
	Phase 1 BCS (Jan 2009)	DP	DP	FH
	Full BCS (Jul 2010)	-	-	DP

Note: DP = Design Projects; FH = Fuel Handling

4.10.2 Project Team Turnover

Throughout the project, roles and responsibilities changed hands a number of times. The project manager changed, the project leader changed twice, there were at least four MTLs and four DTLs. The project stakeholders, such as FH SREs, also changed. Based on stakeholder feedback, turnovers weren't always well managed which lead to extra time being spent by the incoming staff to get up to speed.

Two different design agencies (GE and SNC-Lavalin) were used which created delays and conflict because they were updating the same design documents in parallel. Although competitive bidding resulted in a lower cost, the overlapping project proponents for VSS release 3 and 4 caused some problems.

Having a consistent project team familiar with the project history and structure could help the project team to consistently meet the schedule. However, with a project such as this one spanning 8 years, it would have been difficult to maintain a consistent project team.

4.10.3 Lessons Learned

LL 4.10.1: Resources need to be correctly identified early in the project process. Under resourcing resulted in delays between 2004 and 2006 which added extra time pressure to meet VBO installation targets.

LL 4.10.2: Project team member turnover should be kept to a minimum. Turnovers take time and valuable information is easily lost. It takes time to become familiar with a project and this caused schedule and cost delays. Essential project controls such as accurate record keeping must be in place to assist project turnover.

LL 4.10.3: Projects should not change executing organizations. The VSS executing function went from Design Projects to FH and then back to Design Projects. This high level transition affects smooth project execution.

LL 4.10.4: The project team member turnover process needs to be improved. Information and expertise was lost in transition. Stakeholders identified that turnovers weren’t always well managed during this project, leading to extra time having to be spent on getting up to speed.

LL 4.10.5: When executing a number of related projects in parallel, available resources must be considered as a project constraint. The scarcity of resources impacted the cost and schedule of the projects.

LL 4.10.6: FH staff should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.

4.11 Project AFS and Closeout

4.11.1 Available for Service / Operations Acceptance

The FHPT capital improvement project was declared available for service through operations acceptance on November 30th, 2011, just in time to meet the project AFS milestone. There are still some cameras that aren’t fully functional. Four final AFS documents were signed (see Table 4.6). There were 59 outstanding action tracking items related to the project at the time of AFS (see Appendix B).

Table 4.6: Final AFS Declarations

Master EC	Design ECs	Description	AFS Date
96905	98730, 98518, 98519	Release 1	2011-11-30
96905	98520, 98521	Release 2	2011-11-30
96905	101353, 101352	Release 3	2011-11-30
96905	103382, 103383	Release 4	2011-11-30

Operations Acceptance Declaration was used rather than Available for Service Declaration. Operations Acceptance does not require acceptance from all main stakeholders, just the MTL and operations manager. A project of this magnitude would normally follow the AFS declaration method.

4.11.2 Project Closure

The project closure report [R-11] was issued on November 2nd, 2012, just in time to meet the project closure milestone. The final actual cost was $16.12 M which was lower than the phase 2 full release estimate of $16.16 M which included [redacted]M of contingency. The project closure date was October 31st, 2012 which is one month earlier than the milestone date. Based on the project performance metrics, the project appears to have been a success. CPI is measured against the final approved release (before contingency) plus any contingency released through approved PCRAFs and SPI is measured against the final approved BCS. This does not give a true indication of performance looking back at a project.

A project Lessons Learned document [R-12] was issues on January 16th, 2013 shortly after the CPIR process began. The CPIR report will be prepared by the end of March 2013, thus closing the loop on the entire project. These were deliverables mentioned in the phase 1 full release BCS to be completed under the phase 2 work but the project was closed before their completion.

4.11.3 Lessons Learned

LL 4.11.1: Project milestones should not be declared complete if there are outstanding actions and deliverables. This project was declared AFS with 59 outstanding action tracking items and closed with outstanding deliverables. Outstanding issues may not be addressed in a timely manner due to lack of priority and funding if a project has been closed.

LL 4.11.2: Major projects should be declared available for service through the AFS declaration and not the Operations Acceptance Declaration. With the number of outstanding actions, a conservative decision should have been made and all stakeholders should have agreed to and signed the declaration.

LL 4.11.3: Project closure reports should provide a more accurate look at project performance metrics. Using approved changes as the baseline for final reporting does not give a true indication of overall project performance.

5.0 PROJECT OUTCOMES

5.1 Effectiveness of Final Product in Meeting Original Business Need

The phase 2 full release BCS was approved on July 29th 2010. Section 7 of the BCS contains four measureable parameters to be evaluated as part of the CPIR in order to establish the effectiveness of the final product in meeting the original business need. The required measurable parameter is the avoidance of unit de-rating through improved PT surveillance. Table 5.1 summarizes the measureable parameters in the full release BCS.

Table 5.1: Full Release BCS Measureable Parameters

2010 Full Release Phase 2 CPIR			
Measurable Parameter	**Baseline**	**Target Result**	**How measured & by Whom?**
1. avoid derating thru improved PT surveillance	1. Temp & non-repairable PT VSS is failing & does not cover entire PT	1. provide permanent & maintainable VSS with 90% increase in surveillance area resulting resulting in improved FM availability	1. % visibility coverage of PT during normal ops with VSS alone; reduced operator dose [measured by FH-Technical (SRE)]
2. avoid derating thru improved PT surveillance	2. VSS failing which reqs deviation request for Ops procedures	2. uninterrupted surveillance of fuelling operations	2. camera availability [measured by FH-Technical (SRE)]
3. avoid derating thru improved PT surveillance	3. FFAA bay camera does not cover reqd view of manual ops in ancilliary ports	3. 90% increase in surveillance coverage of manual operations in FFAA ancillary ports	3. % of visibility coverage of ancillary ports [measured by FH-Technical (SRE)]
4. project executed within approved budget & schedule	not applicable	4. key milestones met and project cost within approved release	4. CPI; SPI; milestone adherence [MTL, Design projects to measure]

5.1.1 Parameter 1 – Visibility of the Power Track System and Reduced Operator Dose

The full release BCS states the following measurable parameter:

> *"% visibility coverage of PT during normal operation with surveillance system alone. Reduced operator dose."*

This parameter measures the targeted result of:

> *"a permanent and maintainable surveillance system with 90% increase in the surveillance area resulting in improved FM availability"*

The design manual for the closed circuit television system (NK38-DM-60260) was revised on January 28th 2012 (R001), two months after the AFS date of November 30th 2011. It is unclear how the final design can meet the intent of the design manual, when the design manual was issued after the AFS date.

Reduced Radiation Exposure

The revised design manual states the following under "Functional Requirements"

1. To monitor processes and activities in areas normally inaccessible due to high radiation fields.

2. To reduce radiation exposure of supervisory personnel when monitoring routine maintenance or emergency repairs.

3. To view in the training room, fuelling operations, etc for the training of operating personnel.

Point number two mentions a reduction in radiation exposure, however it does not quantify the reduction by stating what the current radiation dose is, and what the new reduced target must be.

The full release BCS does not quantify dose reduction in any way (stating dose levels before the start of the project and target dose reduction after). The project design package does not contain any calculations or Dosimetry Management System (DMS) audits for radiation dose received by the worker before or after the camera system installation. As a result, compliance with this measure is inconclusive based on the project documentation available.

Performance Requirements (Percent Coverage)

The revised design manual states the following under "Performance Requirements"

> *"The system shall comprise of CCTV cameras, monitors, control unit, key board with joystick, network of cables, receptacles for cameras and receptacles for monitors/control units.*
>
> *The system shall be flexible and shall provide extensive coverage. The system shall have capability to expand CCTV monitoring capability in future. Electrical installation shall meet Ontario Electrical Safety Code.*
>
> *All view coming to the Main Control Room (MCR) shall be recordable as required basis. "*

The performance requirements do not specify an increase in camera surveillance area. Full Release BCS parameter 1 states a 90% increase in surveillance area, however it does not state a baseline value on the existing system. The design package for the surveillance system does not contain any calculations for camera surveillance area before or after the project is complete.

Table 003 in section 2.0 of the camera system design manual summarizes qualitative detail on coverage area for the new system and in shown below:

Table 5.2: Camera Coverage Areas in Design Manual

Section	Coverage Requirements
2.2.1.1 Fuelling Machine and Transport Trolley	1. Snout locking mechanism during homing and locking in reactor channel or FFAA ports. 2. Catenaries during fueling machine transversing 3. Trolley mounted auxiliaries, gauges, counters etc 4. Reactor Area Bridge Drive. 5. Reactor face 6. Indicator of TMM Magazine position providing information on what type of component is being installed in each position (only during outage TMM use) 7. Substitute view of partial power track component inspection defined under section (only during outage or other abnormal condition when Common Service Area (CSA) cameras cannot cover entire power track component due to Trolley movement restriction) 8. Cover entire Trolley area by a hand held camera connecting to the CCTV system to be viewed remotely from MCR.
2.2.1.2 Central Service Area	1. End drum, end drum wheel assembly and end drum support assembly 2. Intermediate roller, end plate assembly, endplate wheel assembly and pillow block bearing surface. 3. Inner side of C channel for any debris, grooved wheel round bar and flat wheel bar. 4. Chain sag, outside side chain pins, carrier bar, outside carrier bar pins, cable, cable riser and coupling frame.
2.2.1.3 East and West Reception Bay	1. Camera to provide view of the ancillary port. The camera shall view the personnel working on the ancillary port. This shall be available to be viewed from the MCR panel. 2. Camera shall provide view of reception bay Irradiated Fuel Discharge Mechanism (IFDM).
2.2.1.4 Wet Flask Handling Area	1. A camera shall be provided in the wet flask handling area for viewing irradiated fuel flask handling and shipping operation.

The project closure report states that the camera project components were installed in Section 1.0 "Deliverables and Milestones". The report makes no mention of meeting the camera system performance requirements mentioned in the design manual (see Table 5.2). With no evidence that the installed system meets the coverage requirements in the design manual, and no basis for comparison available to establish the specific coverage increase requirement of 90%, exact compliance with parameter 1 (surveillance area) is inconclusive.

When interviewed, FH operators considered the increase in camera coverage on the new surveillance system to be negligible. Operators do not feel that the new surveillance system will reduce the possibility of another 2004 incident.

5.1.2 Parameter 2 - Camera Availability

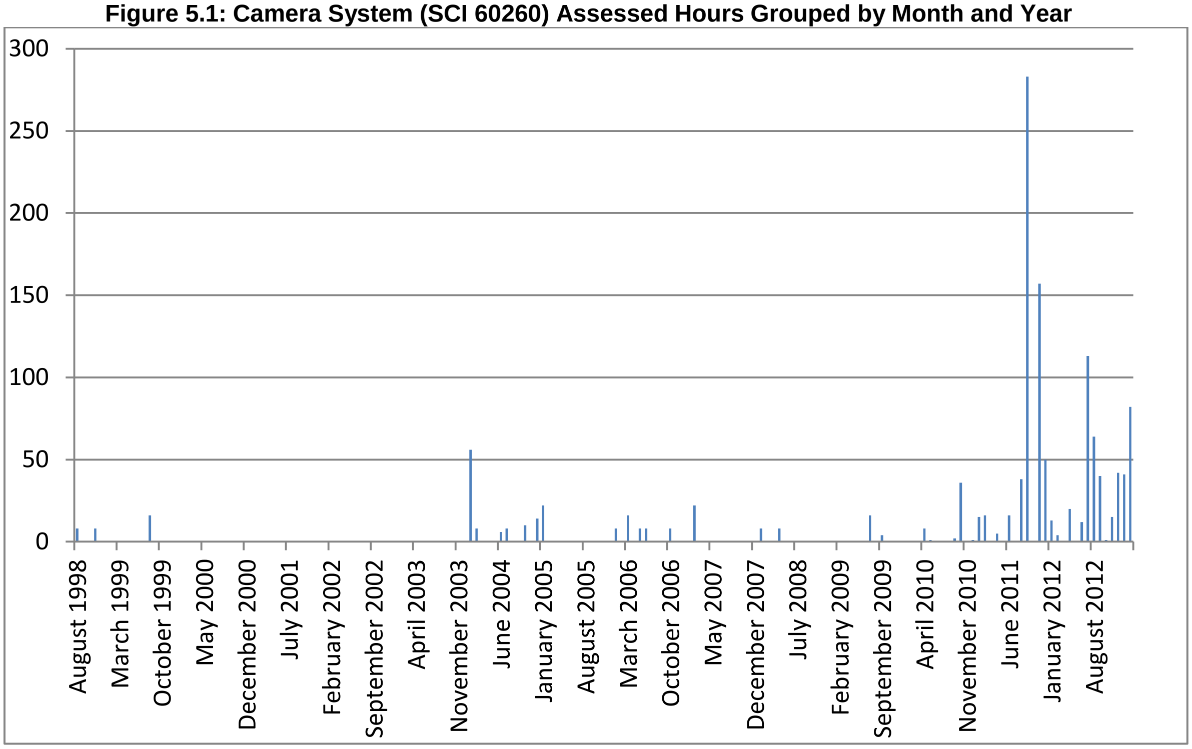
"Camera availability" is stated as a measurable parameter for increased fuelling operation surveillance. The increased surveillance avoids deviation from operating procedures.

The full release BCS does not provide a baseline value for availability over previous years. The project design documents do not provide availability calculations for the previous system. In this report, two different approaches are used to determine if there has been a change in system availability after project installation and AFS November 30th 2011:

5.1.2.1 Quantitative Approach

A quantitative approach is used to attempt to numerically describe equipment availability. If the camera system is unable to perform its function, corrective and/or deficient work will begin to appear. This approach involves an assessment of all Passport work orders entered into the system under the camera system SCI 60260. The camera system work order tasks are filtered to include only corrective and deficient work order types. The assessed hours for all work orders are then grouped and totalized by calendar month and year. Figure 5.1 shows a graph of all assessed hours for SCI 60260, grouped by calendar month and year.

Figure 5.1: Camera System (SCI 60260) Assessed Hours Grouped by Month and Year



Although the assessed hours increased slightly between 2004 and 2010, there is a noticeable increase in the assessed hours around November 2011 (the time the system was installed), and all throughout 2012 and 2013. The year 2004 had the largest number of corrective work order hours assessed prior to the installation of the new surveillance system. The total hours in 2011 and 2012 are three to five times larger than 2004. These results indicate a large amount of corrective work at installation, and continuing while in service. Table 5.3 is a summary of the data in Figure 5.1, grouping all work order tasks by calendar year.

Table 5.3: Camera System (SCI 60260) Assessed Hours Grouped by Year

Year	Total Assessed Corrective / Deficient Hours
2013	123
2012	324
2011	580
2010	48
2009	20
2008	16
2007	22

2006	48
2005	22
2004	102
1999	16
1998	16

There is more corrective / deficient work for the camera system assessed in 2013 and 2012 than any year previous to the installation year (2011). The assessed hours in 2013, have already exceeded one third of the previous year's total in January and February alone.

The increase in assessed hours in 2012 / 13 suggests the availability of the new camera system has decreased. It is possible that the increase in assessed deficient / corrective work hours is due to a work-in period for the system. As such the quantitative approach by itself is not sufficient to determine system availability.

5.1.2.2 Qualitative Approach

The qualitative approach to describe equipment availability looks at system documentation such as heath reports and work order task instructions in order to try to explain the results obtained in the quantitative approach.

System Health Report

System health for the VSS is tracked in the System Health Report (SHR) for the Trolley and Power Track system (SCI 35710). Problems with the camera system appear in Problem ID 5 (system unique indicator #3) of the latest system health report available as of Q1 2013. Table 5.4 summarizes the deficient work orders for the camera system:

Table 5.4: Work Orders Tracked in the SHR

WO / WR	Deficiency
W/R 869100 (W/O 2861819)	Poor image quality on T(3 and T(4 trolley cameras (VC 3 and VC4) .
W/O 2694182	No signal from VC 31, 32, and 37. Control maintenance has determined that there is no signal going to the control room, or to the intermediate panel. Unit 2 outage required for troubleshooting / replacement work.
W/O 2825316	Cameras VC 26 and VC 29 were replaced during the D1231 outage but still do not function. Control maintenance to perform troubleshooting activities.
W/O 2745944	Trolley 2 camera (VC2) found to be defective. Control maintenance has replaced the defective camera, and has rebuilt the defective camera.
W/O 2805413	Trolley 6 camera (VC6) has no signal in the main control room. Control

	maintenance has swapped the camera on Trolley 6 with a working unit on Trolley 5, with no results. Cable troubleshooting work is still outstanding.
W/R 869102 (W/O 2501272, 2863785)	Trolley 5/6 power track camera has been knocked off its mounting. New brackets need to be installed.

Work orders 2861819 and 2745944 are for defective trolley cameras. Consultation with the camera system SRE and the installation OEM has identified two contributing factors for these work orders.

The original trolley mounted cameras (VC1 through VC6) have a design flaw located at the base of the camera unit. The design flaw produces a gradual degradation of the internal cabling at the base of the camera, gradually reducing the image quality. Control maintenance staff has installed replacement parts to correct the design flaw on all stocked spare trolley cameras.

The trolley mounted cameras provide a large viewing area for the operator; however the cameras are mounted in a location that will receive a large dose from the reactors while in service. Although the cameras fail frequently (less than one year of service), replacement cameras are stocked on site. The cameras can be replaced with the reactor units online, the trolley parked inside an FFAA, and with the shield door closed, minimizing dose to the worker.

The failure of the trolley mounted cameras VC3 and VC4 do not represent a concern for system availability. The design flaw has been corrected on all stocked spare units. The failures are equipment lead-in problems that have been corrected.

W/O 2501272 / 2863785 is for a camera that has been physically damaged while in service. The cause of the damage is not yet known, and cannot be attributed to a system availability issue.

W/O 2825316 is for the troubleshooting and / or replacement of two power track cameras (VC26 and VC29). Both cameras stopped working immediately after they were replaced during the D1231 outage. This represents a concern for system availability. Additional troubleshooting work is required to determine the fault and restore availability.

W/O 2694182 requires additional troubleshooting work during a unit 2 outage. Cameras VC31, 32, and 37 were not functioning properly when the surveillance system was commissioned. Additional troubleshooting work is required for the cabling from the camera to the nearest wall-mounted junction box in containment. The cameras must remain out of service until the troubleshooting work can be completed as part of a unit 2 outage. This outstanding corrective maintenance work reduces system availability.

W/O 2805413 is to investigate a loss of video signal from the trolley mounted camera on trolley 6. Continued troubleshooting work is required between the trolley mounted camera and the intermediate amplifier junction box inside containment. The trolley mounted camera on trolley 6 is unavailable.

Of the six items tracked in the Q1 2013 SHR for the Trolley and Power Track System, two items are not a concern for system availability. The remaining four items are a reduction in system availability.

DVR failure

The camera system Digital Video Recorders (DVRs) record video signals from all cameras. The recording is triggered by motion or by the operator (using an built in user interface). There are a total of three DVRs in the system (one per trolley). The DVR module on T(3,4 has failed after less than 2 years of service (WO 2910661). The DVR is not subject to any environmental or radiation hazards. Although the camera system design manual (NK38-DM-60260) does not provide an in-service lifetime, the DVR units are an essential component, allowing the SRE and / or operator to play back historical video to look for equipment defects that may lead to another failure. This represents an availability concern, inhibiting the use of the camera system to help prevent a recurrence of the 2004 event.

Non-Standard Operating Condition

Operating manual NK38-OM-35700 Section 4.3.4 (3) states that a trolley cannot operate in coarse drive if two v-groove wheel cameras have failed or if two flat wheel cameras have failed. One power track v-groove camera and one flat-wheel camera have failed on the T(5,6 power track surveillance system (W/O 2825316, VC26 and VC29). If one more power track wheel camera fails on T(5,6, (VC39 or VC36) the trolley will be restricted to fine drive, reducing its speed by a factor of 12.5 (maximum 16 ft/min as opposed to 200 ft/min), reducing fuel delivery rates on unit 3 and unit 4 by at least 68%.

The failure of the power track cameras on trolley 5,6 reduces system redundancy, and is a loss of system availability.

Blind Roller Inspection

Work order 2875548 is for an operator inspection of the T(1,2 power track rollers every 13 weeks. This work is required as a compensatory measure against failed power track cameras VC31, 32, and 37. The work order instructs the operator to enter the vault to look for damaged or dropped rollers. The reduced availability of the power track cameras on T(1,2 increases operator dose levels, contrary to the original design intent of the system.

Conclusion

The quantitative review has shown an increase in assessed hours for corrective and deficient maintenance. A qualitative review of corrective work orders in the system health report has revealed that four out of the six deficiencies tracked in the SHR are to address system availability problems. The recent failure of the system 3 DVR reduces availability of essential historical video. Power track camera failures have reduced surveillance system redundancy, increasing operator dose as a result of compensatory measures. After installation and acceptance of the surveillance system in November 2011, the surveillance system availability has reduced, resulting in an increase in corrective maintenance workload, increased operator dose, and a loss of surveillance redundancy potentially reducing fuel delivery rates.

5.1.3 Parameter 3 - Visibility of the FFAA Ancillary Ports

Similar to parameter 1, there is no evidence that the installed system meets the qualitative coverage requirements in the design manual, and no basis for comparison available to establish the specific coverage increase requirement of 90%. Exact compliance with parameter 3 is inconclusive.

5.1.4 Parameter 4 – Project Performance Metrics

The project closure report states that the CPI is 1.0 and the project was closed 30 days ahead of schedule indicating that the SPI is also 1.0. All key milestones were also declared completed either ahead or on schedule.

5.2 Training

Operator training was not completed for the FHPT camera upgrades project. Control maintenance training was completed in November and December of 2012 (WO 1924965). The equipment OEM provided five sessions with detailed maintenance and troubleshooting instructions for control maintenance and technical support staff.

5.3 Lessons Learned

LL 5.1.1: Performance parameters must be specific to the business need and project objectives, be measurable and have a measured baseline available. The performance requirements in this project demonstrate camera availability and reduced dose to the operator. It is not clear how these measures will show that the camera system is working to prevent a recurrence of the 2004 incident or to improve system reliability. The following performance parameters could have been used instead and would show that the surveillance system is working, and that it meets the original business need of the project:

- Number of full-length power track roller / chain inspections per year.
- Number of reactor face inspections per year.
- System availability as determined by a measurable parameter, such as:

- hours of saved DVR video per fuelling run for the power track cameras
- hours of saved DVR video per fuel push for the FFAA cameras

LL 5.1.2: Performance parameters must have a measurable baseline in place. The design package must include reports and / or calculations that prove that the design meets the performance parameters. Project close-out documents must include checklists, measurements, or calculations that clearly show how well the installed equipment meets the performance parameters.

LL 5.1.3: Provide training for all stakeholders affected by the project. Ensure that training is added to the project scope and that resources are scheduled as part of project execution.

6.0 SUMMARY OF LESSONS LEARNED

Table 6.1: Summary of Lessons Learned

LL Ref.	Description
LL 3.2.1	At the start of a project, the problem definition and Business Need statement should be defined in the most specific terms possible, allowing specific solutions to be identified and prioritized based on the expected benefit attributable to each solution.
LL 3.2.2	A thorough review of the alternatives should be conducted in the early project phases (initiation phase, early definition phase) to review their implementation practicality and requirements, including the cost and schedule requirements. The evaluation of the alternatives should involve all stakeholders (design, operations, maintenance, OEM, etc.) and should consider the project-specific constraints such as the limited availability of No Fuel Windows in this case.
LL 3.4.1	When several major scopes of work are associated with reducing a financial risk to the company, the outstanding (remaining) financial risk used in the financial evaluation in successive business cases should be revised to reflect the outstanding (non-retired) portion of the financial risk, as appropriate.
LL 3.4.2	It is important that the inputs and assumptions used in the financial evaluations, or NPV calculations, for the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.
LL 4.1.1	Project charters should not identify the specific solutions including specifying the design agency to be used for the proposed modifications. Other options should be pursued rather than jumping to a sole-sourcing design solution that could be more costly than other options.
LL 4.1.2	The problem definition and business need statement should be as clear and specific as possible from the beginning of the project. In this case it is very general and it is difficult to relate the proposed solutions to the business need. A general problem statement leads to scope development and prioritization issues later in the project lifecycle.
LL 4.2.1	Project Execution Plans (PEP) should be developed in parallel with the BCS. The PEP helps document, monitor and control various key project management areas. The BCS should be a summary of much of the information outlined in the PEP.
LL 4.2.2	Project Execution Plans should contain plans for all project management areas. Project 16-31438 had many scope, cost and schedule management issues. The existence of a proper PEP could have helped mitigate the risks.
LL 4.2.3	Proper turnover and document management processes need to be followed for OPG projects to ensure no loss of information. A PEP was developed in 2008 but was lost and never approved. Information from this PEP could not be used for the development of the actual approved PEP.
LL 4.3.1	Projects with multiple initiatives need to have their scope prioritized to ensure effort is being focused on key areas and areas that need to be completed before others can begin. A Scope Management Plan could have helped document the relationship between initiatives and help prioritize the larger number of initiatives.
LL 4.3.2	Projects consisting of a large number of initiatives should be grouped into a number of separate projects based on the business need and objective they are trying to achieve. This would allow the proper amount of resources to be assigned to each project to ensure progress is being made on all initiatives.
LL 4.3.3	When multiple projects exist for a system, the impact of one project must be assessed on the other projects. Due to several parallel FHPT projects, one project's impact on other projects

	was not realized. After the roller endplate modification, the performance of the modification should have been assessed before starting the proposed modifications (DRD and DI system) on the same system.
LL 4.3.4	Projects should not contain initiatives requiring design input from the completion of another project. This was the case for project 16-38472, OM&A FHPT Improvement, as shown in figure 2.1. Those initiatives could also be a second phase of the preceding project, only to be executed based on the results of the design inputs. This would reduce effort and money spent on initiatives that were ultimately cancelled due to the cancellation of DI.
LL 4.3.5	Projects resulting from a major station event should initially be reviewed by a third party to ensure the initiatives are feasible and aligned with the stated business need. The OEM should be contacted immediately for input. Emotions tend to be running high after a significant event and an independent look at the proposed solutions should be completed. Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.
LL 4.4.1	Time pressure should be avoided in order to follow project management best practices. Targeting VBO installation expedited the design phase of the project which resulted in the use of sole sourcing. This had an impact on overall project cost.
LL 4.4.2	Projects requiring field installation should attempt to have their schedule pre-negotiated and committed to by operations and maintenance. However, the use of NFWs for project installations is ineffective as these windows have a tendency to move and cannot be pre-negotiated.
LL 4.4.3	Fuel Handling projects requiring NFWs for installation, should explore the use of FH mini outages to complete the work. More work can be executed because of the reduction in overhead involved with starting work each time. The mini outages should be planned and committed to like a unit outage.
LL 4.4.4	Projects executed in areas with high radiation and limited accessibility should have adequate schedule float in order to meet installation milestones. Due to unexpected breakdown maintenance issues, most of the NFWs were taken away from this project.
LL 4.4.5	When executing project installation work, extra resources should be assigned for timely application of permits and work authorization.
LL 4.5.1	The CPIR team recommends that project cost performance for project closure reports should also show the deviation from the summary of estimate before contingency. CPI based on the most recently approved release is used for project cost management but the CPIR team feels that this does not give an accurate representation of overall cost performance looking back at a project.
LL 4.6.1	Risk Management Plans should be developed early in the project lifecycle in order to guide risk mitigation. Earlier identification of risks, such as schedule unpredictability, could have helped reduce the effect of these risks.
LL 4.6.2	Substantial effort should be spent on correctly identifying potential risks. Many major and foreseeable risks were not correctly identified which lead to cost, schedule and scope management issues. For example, the risk of not completing experimental work, such a DI and DRD, should be an identified risk in order to mitigate the effects of the scope reduction on other ongoing work.
LL 4.7.1	A competitive bidding process should be used to avoid the costs associated with sole sourcing. If time pressures had not been present at the beginning of the VSS project, the use of competitive bidding could have resulted in significant cost savings.
LL 4.7.2	Projects containing multiple releases with overlapping design proponents should only use one design agency. If the releases don't contain completely independent designs, the same design agency should be used to avoid configuration management issues.
LL 4.7.3	Projects containing multiple releases should use the same construction contractor when

	possible. This reduces the overhead required for training and equipment familiarization.
LL 4.9.1	A communication management plan should be developed early in the project lifecycle. This would ensure the right people were receiving the right information at the right time. It would also help communication between other project teams working on the same system in parallel.
LL 4.9.2	Communication between the project team and station operations and maintenance is necessary to successfully complete field installations. Cooperation between the various stakeholders was necessary to get the schedule commitments.
LL 4.9.3	OPG needs a proper document repository and versioning system to accommodate working documents. Passport / Asset Suite and shared folders are not very useful in this area. This would help avoid the loss of important project documentation.
LL 4.10.1	Resources need to be correctly identified early in the project process. Under resourcing resulted in delays between 2004 and 2006 which added extra time pressure to meet VBO installation targets.
LL 4.10.2	Project team member turnover should be kept to a minimum. Turnovers take time and valuable information is easily lost. It takes time to become familiar with a project and this caused schedule and cost delays. Essential project controls such as accurate record keeping must be in place to assist project turnover.
LL 4.10.3	Projects should not change executing organizations. The VSS executing function went from Design Projects to FH and then back to Design Projects. This high level transition affects smooth project execution.
LL 4.10.4	The project team member turnover process needs to be improved. Information and expertise was lost in transition. Stakeholders identified that turnovers weren't always well managed during this project, leading to extra time having to be spent on getting up to speed.
LL 4.10.5	When executing a number of related projects in parallel, available resources must be considered as a project constraint. The scarcity of resources impacted the cost and schedule of the projects.
LL 4.10.6	FH staff should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.
LL 4.11.1	Project milestones should not be declared complete if there are outstanding actions and deliverables. This project was declared AFS with 59 outstanding action tracking items and closed with outstanding deliverables. Outstanding issues may not be addressed in a timely manner due to lack of priority and funding if a project has been closed.
LL 4.11.2	Major projects should be declared available for service through the AFS declaration and not the Operations Acceptance Declaration. With the number of outstanding actions, a conservative decision should have been made and all stakeholders should have agreed to and signed the declaration.
LL 4.11.3	Project closure reports should provide a more accurate look at project performance metrics. Using approved changes as the baseline for final reporting does not give a true indication of overall project performance.
LL 5.1.1	Performance parameters must be specific to the business need and project objectives, be measurable and have a measured baseline available. The performance requirements in this project demonstrate camera availability and reduced dose to the operator. It is not clear how these measures will show that the camera system is working to prevent a recurrence of the 2004 incident or to improve system reliability.
LL 5.1.2	Performance parameters must have a measurable baseline in place. The design package must include reports and / or calculations that prove that the design meets the performance parameters. Project close-out documents must include checklists, measurements, or calculations that clearly show how well the installed equipment meets the performance parameters.

LL 5.1.3	Provide training for all stakeholders affected by the project. Ensure that training is added to the project scope and that resources are scheduled as part of project execution.

7.0 CONCLUSIONS AND RECOMMENDATIONS

In accordance with project management governance and measures, the FHPT Capital Improvement project was deemed to be successful in terms of cost and schedule when compared to the Phase 2 Full Release Business Case Summary (BCS) approved in 2010. A surveillance system has been put in place, which allows remote inspection and real-time monitoring of the FHPT. However, not all VSS cameras are fully functional and outstanding actions still exist.

When looking back at the project, the CPIR team concluded that overall cost performance was not acceptable and scope management and implementation during the project was not well executed. The Partial Release BCS approved in late 2007 forecasted the final project cost to be $9.3 M and included three modifications (DI, DRD and VSS). The Phase 1 Full Release BCS approved in early 2009 forecasted the final cost of the project to be $17.38 M for the three modifications. In mid 2009, five years after the initial event, OPG requested a project scope assessment from the Original Equipment Manufacturer (OEM). The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of the project. This was a result of the OEM assessment leading to a joint review by Fuel Handling and Design Projects. The joint review determined that there was low value for money in proceeding with DI and DRD.

The Phase 2 Full Release BCS in 2010 forecasted the final cost of the project to be $16.16 M, which is approximately $1 M less than the previous BCS, but the scope of the project had been reduced to the VSS modification.

The CPIR team conducted a thorough assessment of project management practices, BCS quality and project outcomes. Project documentation was reviewed and project stakeholder interviews were conducted. Lessons learned have been summarized in section 6 of this report. Recommendations based on the key themes of the lessons learned have been documented below.

Recommendation 1: Fuel Handling Mini Outages bring Predictability to Project Installation Schedules

The CPIR team recommends that the use of FH mini outages with committed dates be explored as an alternative to the use of NFWs for project installation work. NFWs have a tendency to move and competing station priorities may result in bumped project work. Resources can then be assigned to project installation work with more certainty, increasing the probability of achieving project schedule and cost estimates.

The FHPT Capital Improvement project attributed cost and schedule delays to the unpredictability of the installation schedule. NFW commitment was difficult to obtain, NFWs moved and proper resources for permit application and work authorization weren't available when installation work was finally executed. The work was eventually executed successfully using FH mini outages.

Recommendation 2: Milestones and Other Time Pressures should not take priority over Project Management Best Practices

The CPIR team recommends that project management best practices should not be sacrificed to meet deadlines. Milestones should not be declared complete when actions to meet the milestone are still outstanding.

The FHPT Capital Improvement project initially targeted installation during the 2009 VBO. Decisions were made based on the VBO time pressure. Relief from outage milestones was required and GE was awarded a sole source contract to expedite the design process. The project was declared AFS through operations acceptance in November of 2011 with 59 outstanding actions in order to meet the project AFS milestone. The project was closed out in November of 2012 to meet the project closure milestone leaving a number of project closure deliverables incomplete, such as the Lessons Learned document and the Comprehensive Post Implementation Review.

Recommendation 3: Major projects resulting from High Profile Events should undergo an Initial Independent Assessment of the Business Need and Identified Alternatives

The CPIR team recommends that a third party assessment be done early in projects resulting from high profile events. After a major station event, emotions are running high and there is an urgency to quickly correct the identified causes. An independent assessment of the proposed solutions would help identify if those solutions are feasible, if they meet the business need and whether the alternative analysis has been thorough including comprehensive stakeholder involvement.

Key stakeholders interviewed described the actions following the 2004 FHPT as a "shotgun" approach, where a number of solutions were identified and pursued through project 16-38451. The feasibility of the solutions was not determined, a value engineering assessment was not done, the OEM was not contacted and the scope was not prioritized. In the end, 6 of the 12 initial initiatives were cancelled.

Recommendation 4: Clear and Specific Problem Definition and Business Need Statement need to be developed at the beginning of a project

The CPIR team recommends that extra scrutiny be placed on the problem definition and business need statement at the outset of the project lifecycle. A clear and specific problem definition linked to root causes is crucial to enable a thorough alternative analysis, scope identification and scope prioritization. All activities throughout the project lifecycle should be continuously checked against the business need to ensure continuity with the problem definition and proposed solution.

The business need for this project was to improve the reliability and performance of the FHPT. This need did not address the root causes determined through the 2004 FHPT event investigation. The generality of the statement resulted in 12 initiatives being identified for project 16-38451 and 6 of the original initiatives were eventually cancelled. The final scope of project 16-31438, VSS, does not address reliability and performance improvement.

Recommendation 5: An approved Project Execution Plan is needed early in the Project Lifecycle

The CPIR team recommends that a thorough project execution plan be prepared and approved during the early stages of a project. A plan should be in place to document, monitor and control all project management knowledge areas to ensure effective project execution.

The FHPT Capital Improvement project was lacking a Project Execution Plan (PEP) until February of 2010. The initiatives under this project were started in 2004 and a PEP should have been prepared at that time to guide initiative progression. The implementation of a plan in 2010 helped bring the project to completion. If it was developed earlier in the project lifecycle, the project could have benefitted in terms of scope, cost, schedule, and risk management. Having proper plans in place could have also helped manage resource and scope relationships between the multiple FHPT projects.

Recommendation 6: Alternatives to Sole Source Contracts should always be explored

The CPIR team recommends that the justification for sole source work be closely scrutinized to ensure that benefits from the competitive bidding process are not lost. GE was chosen as the sole source for the camera system on the basis of their experience with fuel handling technology. There was no technical basis for this decision, as the surveillance system technology is not dependant on any unique aspects of the fuel handling system technology.

The FHPT capital improvement project used a sole source contract with GE to expedite the design phase of the project. VSS Release 4 went to competitive bidding which resulted in significant cost savings. Had this approach been used from the initial stages of the project, final project costs could have been lower.

Recommendation 7: An improved Document Repository and Versioning System is required

Having a proper document control system for working documents is useful for tracking changes and ensuring documentation is not lost. Documentation was lost at various stages of the project. Lost documentation leads to rework and loss of information crucial to decision making. Asset Suite and shared drives are not an effective means of managing working documents.

The FHPT Capital Improvement project CPIR revealed that project documentation was lost a number of times throughout the project lifecycle. An earlier version of a prepared PEP was lost, resulting in rework and not having a PEP approved until 2010. When CPIR interviewees attempted to retrieve project documentation from the shared drive for the CPIR team, they found documentation was missing.

8.0 GLOSSARY

AFS	Available For Service
AISC	Asset Investment Screening Committee
BCS	Business Case Summary
BOE	Basis Of Estimate
CPI	Cost Performance Index
CPIR	Comprehensive Post Implementation Review
DI	Dynamic Instrumentation
DNGS	Darlington Nuclear Generating Station
DP	Design Projects
DRD	Dropped Roller Detection
DTL	Design Team Leader
FEP	Front End Planning
FH	Fuel Handling
FHPT	Fuel Handling Power Track
FTL	Field Team Leader
GE	General Electric
IEV	positive Impact on Economic Value
IF	Irradiated Fuel
LL	Lessons Learned
MTL	Modification Team Leader
NPV	Net Present Value
OEM	Original Equipment Manufacturer
OM&A	Operations, Maintenance & Administration
OPEX	Operating Experience
OPG	Ontario Power Generation
PCRAF	Project Change Request Authorization Form
PEP	Project Execution Plan
PIR	Post Implementation Review
PM	Project Management
PO	Purchase Order
PT	Power Track
QA	Quality Assurance
REIS	Report of Equipment In Service
RMP	Risk Management Plan
RMP	Reactivity Management Plan
SCR	Station Condition Record
SPI	Schedule Performance Index
SRE	System Responsible Engineer
T&M	Time and Material
T(X,Y	Trolley System Identifier (X,Y = 1,2 or 3,4 or 5,6)
TMOD	Temporary Modification
VBO	Vacuum Building Outage
VSS	Video Surveillance System

9.0 REFERENCES

[R-01] “Fuelling Machine Power Track Rehabilitation Project 38451 Charter”, D-PCH-63578-10001, 2004-Sep-14

[R-02] “Fuelling Machine Power Track Rehabilitation Project: 16-38451 Full Release Business Case Summary”, D-BCS-63578-10005, 2006-Mar-09

[R-03] “Project Closure Report F/H Power Track Rehabilitation Project 16-38451”, FIN-FORM-PA-005, 2008-May-02

[R-04] “FH Power Track Improvement – Capital Funded Project 31438 Charter”, D-PCH-63578-10004, 2006-Apr-04

[R-05] “FH Power Track Rehabilitation 16-38472 OM&A 16-31438 Capital – Developmental Release Business Case Summary”, D-BCS-63578-10008, 2007-May-28

[R-06] “FH Power Track Rehabilitation 16-38472 OM&A 16-31438 Capital – Partial Release Business Case Summary”, D-BCS-63578-10009, 2007-Nov-13

[R-07] “Fuel Handling Power Track Modifications – Capital - 16-31438 – Full Release (Phase 1) Business Case Summary”, D-BCS-63578-10010, 2009-Jan-26

[R-08] “Fuel Handling Power Track Capital Improvement Project 16-31438 – Full Release Business Case Summary”, D-BCS-63578-10006, 2010-Jul-29

[R-09] “Approval to Write Off Costs for Project 16-31438”, NK38-CORR-63578-0313360, 2009-Dec-21

[R-10] “Fuel Handling Cable Carrier Condition Assessment”, NK38-IR-0-63578-10001, 2009-Aug-11

[R-11] “Project Closure Report FH Power Track Capital Improvement Project 16-31438”, FIN-FORM-PA-005, 2012-Nov-02

[R-12] “Fuel Handling Power Track Cameras Lessons Learned”, D-LLD-60260-10001, 2013-Jan-16

[R-13] “SCR D-2004-00642 Trolley Drive Abnormal Stop”, D-2004-00642, 2004-Jan-21

[R-14] “Darlington NGS – Fuelling Machine Power Track Risk Assessment”, P0440/RP-005, 2004-Nov-05

[R-15] “DNGS Fuel Handling Power Track Improvement Project 16-31438 Project Execution Plan”, NK38-PEP-63578-0278117, 2010-Feb-15

Appendix A: Terms or Reference

Terms of Reference for Comprehensive Post-Implementation Review on Project 16-31438: Fuel Handling Power Track Improvement

A.1.0 BACKGROUND

On January 21st, 2004 at about 16:00 hours, the Darlington Fuel Handling Power Track (FHPT) system experienced a functional failure (SCR D-2004-00642). Intermediate roller #11 suffered a mechanical failure and had fallen into the lower cable pan becoming foreign material. The PT guide roller drum ran over the failed intermediate roller and broke free of its mounting. The guide roller drum shaft projected to the south of the main roller drum and began to interfere with supporting steelwork, halting motion of the FHPT system.

The failure caused significant damage to the Trolley (1,2 Power Track system, resulting in a 21 day outage of Unit 2 and a de-rating of Unit 1 to 59% for 15 days. The cost of the failure was $45M.

The root cause investigation on SCR D-2004-00642 was completed on March 16th, 2004. Assignments 9 and 10 called for an extensive failure analysis and risk assessment to identify initiatives that would reduce the high risk of failure of the FHPT system.

Risk assessment P0440/RP/005 (November 5th, 2004) identified the need for an improved surveillance system on the FHPT system as a means of reducing the operational risk, and for ensuring an effective maintenance program.

In April 2006 Project Charter D-PCH-63578-10004 was approved for capital project 16-31438, with the following objectives (critical success factors):

1. Design and installation of a Dynamic Instrumentation System (DI)
2. Design and installation of a Surveillance System (VSS)
3. Design and installation of a Failure Detection System (DRD)

On May 28th, 2007 the initial development Business Case Summary (D-BCS-63578-10008) for preliminary engineering was approved for $1.38 M. On November 13th, 2007 a partial BCS (D-BCS-63578-10009) was approved for $4.4M to commence design activities. On January 26th, 2009 a full release BCS (D-BCS-63578-10010) for phase 1 was approved for a further $8.53 M.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of a third party assessment leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

On July 29th, 2010 the full release BCS D-BCS-63578-10006 was approved for an additional $1.83 M for the completion of the Surveillance System for a final total of $16.16 M. The BCS states that a Comprehensive Post Implementation Review is required.

A.2.0 PURPOSE

OPG-PROC-0056 requires that a Comprehensive Post Implementation Review (CPIR) be completed if the project sponsor requires it. The full release BCS for project 16-31438 (D-BCS-63578-10006) states that a CPIR is required under section 7. The BCS provided a target CPIR approval date of November 31st, 2012. In a memorandum dated November 1st, 2012, the Chief Financial Officer approved a new CPIR approval date of March 30th, 2013.

The purpose of a CPIR is as follows:

- Verify the achievement of planned benefits identified in the business case and capture any other quantitative and qualitative outcomes of the investment.

- Assess the effectiveness of the project's intent, project charter, project execution plan, project execution, and operational performance results in meeting the business needs and the investment objectives stated in the BCS of the project.

- Review the appropriateness of risk management from business case approval through project completion and document lessons learned in different aspects of risk management including identification, analysis, mitigation plan, and monitoring and control throughout the life of the project.

- Review the effectiveness or quality of the BCS of the project looking back from results to provide feedback for future decisions. The financial evaluation used in the BCS should be re-assessed using actual results and documented in completed PIRs.

A.3.0 SCOPE

The DNGS Fuel Handling CPIR team will examine available project documents and records, and conduct interviews with key project participants and stakeholders, in order to:

- Evaluate the extent to which the promised results and the benefits stated in the approved business case were achieved, considering any assumptions or circumstances which may have changed since the original project approval;

- Review the project management methods and practices that were implemented throughout all project phases, in order to evaluate their effectiveness and impact on project outcomes; and

- Identify key lessons learned that can be captured and used to improve investment and project management practices within OPG. Where possible, the team will make recommendations as to how these lessons learned can be implemented to provide sustained improvements.

A.4.0 DELIVERABLES

The primary deliverable will be a Comprehensive PIR report on Project 16-31438 including the following:

- An Executive Summary, Conclusions and Recommendations.
- A Background section with a review of the project history and rationale.
- An Assessment section which:
  - Reviews project results and other measures specified in the Comprehensive PIR Plan and re-evaluates measures specified in the BCS such as NPV (Net Present Value) against actual results.
  - Examines the project execution plan, scope management, program and resource management, execution, risk management, and the handling of health and safety issues.
  - Documents lessons learned in all aspects (doing the right things, doing them the right way, doing them well and getting the benefits) of the investment.
  - Reviews overall customer satisfaction with the project as well as overall product quality and realized benefits to date.

In addition, a summary of major findings and recommendations will be prepared for presentation on request to Nuclear or Corporate audiences. Records, notes and other working papers will be filed with the DNGS project records upon completion of the review.

A.5.0 SPONSOR

The CPIR sponsor is Steve Ramjist, Director of Operations & Maintenance at Darlington.

A.6.0 REVIEW TEAM

Name	Title	Department
Bill Barron	Senior Technical Engineer	DN Performance Engineering
Justin Julian	Senior Technical Engineer	DN Performance Engineering
Mukesh Mishra	Senior Technical Engineer	DN Design Projects
Silvester Wong	Senior Planning Engineer/Financial Analyst	Asset Planning & Integration
Violeta Garcia-Lee	Senior Planning Engineer/Financial Analyst	Asset Planning & Integration

A.7.0 REFERENCE DOCUMENTS

The CPIR report will base its conclusions and recommendations on the following documents:

Document	Document Number	Date
Project Charter	D-PCH-63578-10004	04-Apr-2006
BCS – Developmental Release	D-BCS-63578-10008	28-May-2007
BCS – Partial Release	D-BCS-63578-10009	13-Nov-2007
BCS – Full Release (Phase I)	D-BCS-63578-10010	26-Jan-2009
BCS – Full Release	D-BCS-63578-10006	29-Jul-2010
Scope Cancelation Memo	NK38-CORR-63578-0313360	26-Nov-2009
Project Execution Plan	NK38-PEP-63578-0278117	15-Feb-2010
Project Closure Report	FIN-FORM-PA-005	14-Nov-2012
PCRAF (8 in total)	N-FORM-10607	
REIS (3 in total)	FIN-FORM-PA-004	
EC List	See Master EC 96905	15-May-2012
AFS	See Master EC 96905	01-Nov-2011
BCS – Project 16-38472 (OM&A)	D-BCS-63578-10011	05-May-2010
Project Closure Report 16-38472	FIN-FORM-PA-005	11-Oct-2012

Additional documents may be added to this list as the CPIR document review and interview process takes place.

A.8.0 WORK PLAN

The team will target to complete its research and interviews and prepare a report for submission by March 30th, 2013.

	Description	Accountability/ Lead	Target Completion Date
1.	Prepare draft Terms of Reference (TOR), scope of work and schedule, identify team	Sponsor /Delegate	31-Dec-2012
2.	CPIR Workshop	Investment Planning	08-Jan-2013
3.	Review and confirm TOR with Team Members / 1st Team familiarization meeting; Finalize TOR	Team Leader	14-Jan-2013
4.	Project Documentation Review	Team	25-Jan-2013
5.	Conduct Interview Sessions with Stakeholders	Team	8-Feb-2013
6.	Analysis and Draft Report Compilation	Team	01-Mar-2013
7.	Draft report - Review with Key Stakeholders	Team	15-Mar-2013
8.	Finalize and Submit Final Report to Project Approval Authority	Team Leader	30-Mar-2013

A.9.0 SIGNATURES

Prepared By:	William Barron	14-JAN-2013
	Bill Barron – CPIR Team Leader	Date
Reviewed by:		14 Jan 2013
	Fred Mason – Section Manager Darlington Fuel Handling Engineering	Date
Approved by:		Jan 14, 2013
	Steve Ramjist – Project Sponsor Director - Operations & Maintenance Darlington	Date

Appendix B: AFS Outstanding Action Tracking Items

AR #		Title
28134884	1	AFS - LAUNCH EQUIP MINOR REVS, DEC 98730, 98519 & 98518
28134884	2	AFS - RELEASE OF E-FILES FOR CD UPDATE, DEC 98730, 98519
28134884	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134884	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC 98730, 98519 & 98518
28134884	5	AFS - DRAWING UPDATE EC# 98730 (CIVIL)
28134884	6	AFS - DRAWING UPDATE EC# 98519 AND 98518 (ELECTRICAL)
28134884	7	AFS - NON-DRAWING UPDATE, DEC 98730, 98519 & 98518
28134884	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 98730 (CIVIL)
28134884	9	AFS - APPROVE DRAWINGS FOR ISSUE EC# 98519 & 98518 (ELEC)
28134884	10	AFS - APPROVE NON-DRAWINGS, EC 98730, 98519 & 98518
28134884	11	AFS - CONTROLLED DOCUMENTS ISSUE, EC 98730, 98519 & 98518
28134884	12	AFS - DESIGN EC CLOSE-OUT FOR EC 98730, 98519 & 98518
28134885	1	AFS - LAUNCH EQUIPMENT MINOR REV, DEC 98520 & 98521
28134885	2	AFS - RELEASE OF E-FILES FOR CD UPDATE, DEC 98520 & 98521
28134885	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134885	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC 98520 & 98521
28134885	5	AFS - DRAWING UPDATE EC# 98521 (CIVIL)
28134885	6	AFS - DRAWING UPDATE EC# 98520 (ELECTRICAL)
28134885	7	AFS - NON-DRAWING UPDATE, DEC 98520 & 98521
28134885	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 98521 (CIVIL)
28134885	9	AFS - APPROVE DRAWINGS FOR ISSUE, EC# 98520 (ELECTRICAL)
28134885	10	AFS - APPROVE NON-DRAWINGS, EC 98520 & 98521
28134885	11	AFS - CONTROLLED DOCUMENTS ISSUE, EC 98520 & 98521
28134885	12	AFS - DESIGN EC CLOSE-OUT FOR EC 98520 & 98521
28134886	1	AFS - LAUNCH EQUIPMENT MINOR REV DEC 101353 AND 101352
28134886	2	AFS - RELEASE OF E-FILES FOR CD, DEC 101353 AND 101352
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Niagara Tunnel Project
Post Implementation Review

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Niagara Tunnel Project

Post-Implementation Review

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Contents

Executive Summary

The Niagara Tunnel Project was intended to take advantage of additional water available from the Niagara River under the Niagara Diversion Treaty, thereby increasing the annual energy output of the Sir Adam Beck (SAB) generating complex by up to 1.6 TWh per year. When the OPG Board of Directors approved it in July 2005, the new tunnel was expected to be in-service by June 2010, and the cost was estimated to be $985 million.

Substantial geotechnical investigations to establish the subsurface conditions along the tunnel route had been carried out over several years prior to the Project. Nevertheless, unexpectedly difficult rock conditions were encountered within the Queenston Shale layer during the first year of tunnel mining. This resulted in a significant delay and Contractor claims for additional costs that required revision of the Project schedule and budget and approval of a Superseding Business Case by the OPG Board in 2009. Under an amended agreement with the Contractor, a new target cost and target schedule were established that set the approved tunnel in-service date as December 2013 and the revised Project budget, including contingency, at $1,600 million. The tunnel was completed and put in service in March 2013 and the final Project cost is now expected to be approximately $1,464 million.

The completed tunnel is 10.2 km long with a finished internal diameter of 12.7 m. It reaches a maximum depth below the surface of 140 m. The facility also includes a new intake and modifications to the existing International Niagara Control Works upstream of Niagara Falls, and an outlet with an emergency closure gate at the SAB end. The tunnel discharges into the Pumping Generating Station Canal near the PGS reservoir. The new tunnel has met its key business objective of delivering 500 m^3/s of additional flow to the SAB Complex.

The Project was carried out using a Design-Build approach, with Strabag AG of Austria being the prime Contractor. A Tunnel Boring Machine manufactured by the Robbins Company under subcontract to Strabag was used to excavate the tunnel. Hatch Mott MacDonald acted as OPG's Owner's Representative throughout the Project.

6.79 million labour hours were worked on site over the eight years of construction. A total of 735 days were reported lost due to work-related injuries or illnesses for an overall LTI frequency of 0.94. This was below the Ontario construction industry average over that period. In addition, all Environmental Assessment and Community Impact Agreement commitments for the Project were met.

1 Introduction

The Sir Adam Beck (SAB) hydroelectric complex at Niagara consists of two generating stations (SAB1 and SAB2), with a total generating capacity of 1,960 MW, and a Pumped Generating Station (PGS) with a capacity of 174 MW. The PGS is used to pump and store water during off-peak periods for use during periods of peak electricity demand.

Water for SAB1 originally came from the Chippawa-Queenston Power Canal, built in the 1920s. In the early 1950s, two underground tunnels were built to provide water for SAB2. The recent Niagara Tunnel Project (NTP or Project) was undertaken to construct a new diversion tunnel to convey approximately 500 m^3/s of water from the upper Niagara River to the SAB complex. This flow would allow the SAB complex to generate an additional 1.6 TWh[1] per year of energy, an increase of 14% above the then current 12 TWh.

A Tunnel Boring Machine (TBM) was used to create a 10.2 km long tunnel with a finished internal diameter of 12.7 m. The tunnel reaches a maximum depth below the surface of 140 m. The Project also included a new intake along with modifications to the existing International Niagara Control Works (INCW), an outlet with an emergency closure gate near the PGS reservoir, and removal of the PGS canal dewatering structure.

The Project was approved for execution on July 28, 2005. The originally approved in-service date of the tunnel was June 2010 and the estimated total cost of the Project at release was $985 million.

The contract for construction of the tunnel and associated works was awarded to Strabag AG of Austria in August of 2005 and work at the outlet site began in September 2005. After delivery and assembly of the TBM, tunnel mining started in September 2006. Due to delays caused by unexpectedly difficult rock conditions, mining of the tunnel was not completed until March 2011. Construction of the tunnel liner started in December 2008 and liner grouting – the last stage of tunnel construction – was completed in February 2013. After removal of the cofferdam at the intake, and the rock plug at the outlet, the tunnel was watered up and placed in service in March 2013. Testing showed that the tunnel has achieved the guaranteed flow rate. The final Project cost will be approximately $1.464 billion.

The Project was selected as the "North American Project of the Year for 2013" by *International Water Power & Dam Construction* magazine, and in November 2013 the Project was also named "Canadian Project of the Year" by the *Tunnelling Association of Canada*. The Project also received a "2014 Award of Excellence" from

[1] This estimate of additional energy was subsequently reduced to 1.5 TWh.

the Association of Consulting Engineering Companies Canada and a "2015 Grand Award" from the American Council of Engineering Companies.

The cost and duration of this Project required that a Comprehensive Post Implementation Review (PIR) be carried out in accordance with OPG Procedure FIN-PROC-0056. A Comprehensive PIR is an independent review of a completed project conducted in order to:

- Verify the achievement of planned benefits identified in the business case and capture any other quantitative and qualitative outcomes of the investment.
- Assess the effectiveness of the project's intent, project charter, project execution plan, project execution, and operational performance results in meeting the investment objectives stated in the Business Case Summary of the project.
- Review the appropriateness of risk management from Business Case approval through project completion and document lessons learned in different aspects of risk management including identification, analysis, mitigation plan, and monitoring and control throughout the life of the project.
- Review the effectiveness or quality of the BCS of the project looking back from results to provide feedback for future decisions.

The PIR Plan included in the original (2005) Business Case supporting approval of the NTP established parameters, targets and measures for assessing the Project outcomes. A Superseding Business Case (SBCS) approved in 2009 reset the targets for these outcomes, as shown below:

Table 1.1

Parameter	2005 BCS Target	2009 SBCS Target	Measure
Tunnel capacity	500 m^3/s	500 m^3/s	Flow test[2]
In-service date (Including contingency)	June 2010	December 2013	Contract substantial completion date (with approved changes)
Cost	$985 million	$1,600 million	Actual cost compared to approved release

This PIR report compares the actual Project outcomes against the original and subsequently modified and approved targets, and also discusses elements of the project management and risk management processes that affected these outcomes. A very comprehensive history of the NTP has been documented in evidence supplied for the

[2] Test was to be done by the Design/Build Contractor with oversight by an independent Chief of Test.

Ontario Energy Board (OEB) rate hearings[3], and therefore only significant and relevant highlights of that history will be repeated in this report.

It should be noted that the overall Project release also included a $43.9 million associated project to make modifications to the retired Ontario Power and Toronto Power Generating Stations, both owned at the time by OPG, as part of a 2005 agreement for transfer of these stations to the Niagara Parks Commission (NPC). This project, which was managed directly by OPG in parallel with the NTP, and completed in July 2007, is not part of the scope of this PIR except as it relates to the overall Project cost.

The PIR findings in this report were based primarily on a review of Project documents, such as the Charter, Business Case(s), Project Execution Plan, risk documentation, monthly reports, event logs, etc. Where necessary for clarification, interviews with selected Project participants provided additional information. An extensive electronic Project document repository was very helpful in conducting this PIR.

Throughout this report where the term “Contractor” is used, it may include Strabag, the prime contractor, as well as Strabag’s subcontractors. The current Niagara Operations group was known as the Niagara Plant Group (NPG) during most of the Tunnel Project, and the latter title is used within this report.

2 Project Origin

The Niagara Diversion Treaty of 1950 defines the minimum seasonal Niagara River volumes[4] that must be allowed to flow over Niagara Falls to preserve its value as a scenic attraction. Any flow in excess of these minimums is available equally between the United States and Canada for diversion for hydroelectric power production. OPG has the exclusive right to use the Canadian share of the diversion flow. This share ranges from about 600 to 3,000 m^3/s, and averages about 2,000 m^3/s. This available flow is greater than the 1,800 m^3/s capacity of the original SAB diversion facilities (canal and two tunnels) about 65 per cent of the time. By constructing new facilities to increase the diversion capacity to about 2,300 m^3/s the available flow would exceed OPG’s diversion capacity only about 15 per cent of the time.

Feasibility studies for an expansion of Ontario Hydro's hydroelectric facilities at Niagara, to use more of the available flow, had started in 1982. Definition Phase engineering and environmental assessment work for the “Niagara River Hydroelectric Development” started in 1988. At the time, the proposed new development would have included two new tunnels and a new underground powerhouse (SAB3) at the SAB complex. An

[3] OECB Case EB-2013-0321 “Capital Expenditures – Niagara Tunnel Project”, Exhibit D1, Tab 2, Schedule 1 September 27, 2013

[4] The Niagara Diversion Treaty requires that 100,000 cfs (2,832 m3/s) be allowed to flow over the Falls from 8:00 am until 10:00 pm between April 1 and September 15, and from 8:00 am until 8:00 pm between September 16 and October 31. At all other times the allowable flow is 50,000 cfs (1,416 m3/s.

Environmental Assessment (EA) for the proposed project was submitted in March 1991 but work on the project was suspended in 1993 during a major corporate reorganization. Nevertheless, the EA approval was obtained in October 1998. In the meantime, Ontario Hydro had written off the Definition Phase expenditures of $57 million.

The EA approval gave Ontario Hydro the flexibility to undertake the development in phases. In February 1998, a decision was made to proceed with the construction of only one tunnel. Tenders were called for detailed design and construction, and a preferred bidder was selected. However, work was again suspended indefinitely in June 1999 due to another reorganization and corporate funding constraints related to the decision to proceed with the Pickering A Restart. A Project Closeout Report was prepared to document the procurement process to that point, and to identify actions to be taken in the event the project was restarted. Expenditures in 1998-99 totalled $2.5 million and were also written off.

In November 2002, the Provincial Government announced that it would ask OPG to proceed with a new tunnel at Niagara; however, no formal direction to do so was given at the time. Subsequently, the new Government elected in 2003 stated that it wished the project to proceed as soon as possible. In early 2004, the Provincial Government also indicated that the SAB complex, including the new tunnel, would be included as part of OPG's rate regulated base load hydroelectric generation. Under this condition, all "prudently incurred costs" for the tunnel would be recoverable[5].

An agreement between the NPC and OPG, dated February 18, 2005, committed OPG to complete remedial work at the retired Ontario Power and Toronto Power generating stations, both owned by OPG, as part of reversion[6] of these stations to the NPC which planned to use them as a visitor attraction. In exchange for these stations, the NPC would grant exclusive Canadian Niagara River water rights to OPG until 2056. An associated $10 million settlement with Fortis Ontario, approved by the OPG Board on February 8, 2005, secured an irrevocable assignment of the water associated with Fortis' Rankine GS[7].

One additional consideration at the time, influencing the timing of the tunnel project, was the expected need to take the existing 83-year old SAB1 power canal out of service for up to a year to allow remedial work to be done. Because this canal delivered about one third of the water needed for the SAB Complex, this would have led to a generation

[5] This was subsequently formalized under Ontario Regulation 53/05, effective April 1, 2005.

[6] The reversion subproject was managed by OPG and completed in August 2007 at a total cost of $39.7 million. Construction work was carried out by Peter Kiewit and Sons, with Owner's Representative services by Klohn Crippen and MWH.

[7] Fortis was the owner of Canadian Niagara Power which had an agreement with NPC, dating from 1892, for Niagara River water rights for the Rankine Generating Station. The franchise agreement was due to expire on April 30, 2009 when the Rankine station would revert to the NPC. The (Canadian) water rights associated with the franchise agreement represented approximately 283 m^3/s of Niagara River flow.

loss of between 2.7 and 4.0 TWh. Completion of the new tunnel prior to this remedial work, scheduled for 2011, would reduce the generation loss. However, as of the date of this report, this work has been deferred until 2021.

On June 24, 2004, the OPG Board of Directors approved a partial release of $10 million to restart Definition Phase planning work and to conduct a Request for Proposal process for a single tunnel project. At that time, the estimated cost of the project, based on escalation of the lowest bid price received in 1998, was approximately $600 million. A Project Charter, authorizing the Definition Phase, was approved in January 2005. After completion of the RFP and contractor selection process, as well as other pre-project planning activities, the Business Case Summary along with supporting information requesting OPG Board of Directors approval of the Project, designated as EXEC-0007, was submitted and approved in July 2005.

3 Project Approval

3.1 Business Objective

The Business Case Summary for OPG Board approval in 2005 stated that the overall Project objective was to:

"Design, construct and commission a new water diversion tunnel to convey 500 m^3/s of water from the upper Niagara River to the Sir Adam Beck GS complex at Queenston, to capture a unique, site-specific opportunity for OPG to produce additional, low-cost, renewable and environmentally sustainable energy for its customers, enhancing the existing hydroelectric facilities in the efficient use of Niagara River flow available to Canada for power generation."

The recommendation approved by the Board also established as objectives for the Project that it be completed at a total cost of $985 million, including $22.5 million previously approved for project development, and that it be placed in service by June 2010.

3.2 Alternatives

The Business Case considered by the Board presented two alternatives:

Base Case – Do Nothing

The Do Nothing option would have foregone the opportunity for OPG to increase its use of the Niagara River water available to Canada for power generation and thereby increase average annual energy output from the SAB generating stations. Also, remedial work at the retired Ontario Power and Toronto Power generating stations, would still have been required to meet OPG's commitments under the Niagara Exchange Agreement for the reversion of these stations to the NPC. A write-off of about

$37 million would have been taken to cover project development expenditures committed to date ($22.5 million) and the forecast remaining costs associated with the reversion agreement work. This alternative would also have resulted in a temporary generation loss of between 2.7 and 4 TWh while the canal was taken out of service for the remedial work planned at the time.

Alternative 1 - Design & Construct a Diversion Tunnel (Preferred Alternative)
The preferred and recommended alternative was to design, construct and commission the new diversion tunnel to convey approximately 500 m^3/s to the SAB Complex. This alternative would be done through a design-build contracting approach, intended to minimize the risk to OPG and "achieve price and schedule certainty".

3.3 Financial Analysis

Since the Niagara Tunnel was expected to be part of OPG's regulated hydroelectric assets and receive a regulated rate, including cost recovery and a return on capital, financial metrics other than NPV and/or ROI were used in evaluating the economics of the investment relative to other generation options. These metrics were:

- Levelized Unit Energy Cost (LUEC) - representing the price required to cover all forecast costs, including a return on capital over the service life, escalated over time at the rate of inflation. LUEC permits a consistent cost comparison between generation options with different service lives and cost flow characteristics.
- Equivalent Power Purchase Agreement (PPA) Price - representing the price required if the Project had been bid into the RFP[8] for renewable energy. EPPA was similar to LUEC except only 15% of the PPA was escalated at the Consumer Price Index.
- Revenue Requirement - a measure representing the annual accounting cost of this Project including an allowed return on capital employed. Revenue Requirement generally declines over time as the rate base is depreciated.

[8] In 2004 and 2005, the Ontario Ministry of Energy had issued three requests for proposals (RES I, RES II and RES III) to acquire approximately 1300 MW of renewable energy supply capacity.

These metrics all reflected full recovery of costs, including a return on the investment. The analysis results were as follows:

Table 3.1

Financial Measure	Base Case	Preferred Alternative
Initial or remaining costs ($ million)	14	963
LUEC (¢/kWh in 2005$)		4.8
Equivalent PPA Price (¢/kWh in 2011$)		6.7
Revenue Requirement (¢/kWh in 2011$)		5.8
Revenue Requirement for OPG Baseload Hydroelectric (¢/kWh in 2011$), including 10% return on equity	3.8	3.9

The estimated equivalent PPA Price of 6.7 ¢/kWh (2011$) was less than the estimated average PPA Price of 8.0 ¢/kWh (2011$) for the successful proponents in response to the RFP that had recently been issued by the Province for renewable electricity supply alternatives.

The financial analysis concluded that completion of the Project would result in a significant increase in average annual energy output from the SAB complex with only a marginal increase in the estimated required regulated rate for OPG's hydroelectric assets.

Also as part of the Business Case, a sensitivity analysis was done to examine the impact of several factors on the Project economics, as shown below:

Table 3.2

Sensitivity Analysis (June 2010 In-Service Date)	**Incremental Energy TWh**	**LUEC (¢/kWh in 2005$)**	**Equivalent PPA Price (¢/kWh in 2011$)**	**Revenue Requirement (¢/kWh in 2011$)**
Preferred Alternative	1.6	4.8	6.7	5.8
Water availability				
- Lower quartile for first 5 years of service	0.7	5.4	8.1	n/a
- Upper quartile for first 5 years of service	2.4	4.2	5.5	n/a
- Overall reduction of 5% in Niagara River Flow	1.2	6.4	9.3	n/a
Higher cost (+10%)	1.6	5.2	7.4	6.3
Shorter (30 year) Service Life	1.6	5.8	7.6	7.1
Elimination of 10 Year Gross Revenue Charge Holiday	1.6	5.8	8.5	9.1
Other Renewable Supply			8	

3.4 Risks

Given the expected cost and duration of the NTP, as well as problems that had been encountered with the Pickering A Restart Project, it was known that risk management would be a key concern of the OPG Board of Directors when considering the Project for approval. Therefore qualitative and quantitative risk assessments, as described in Section 4.7, were done with the assistance of an external consultant, prior to submission of the Business Case for approval.

3.4.1 Qualitative Risk Assessment

The Business Case Summary listed 20 risks that had been identified through the pre-release stages of the risk management process. The qualitative risk assessment process sorted the risks into those having an expected high, medium or low impact on the Project objectives. The following table lists the risks with a “high” (before mitigation) rating[9] as of the date of Project release, and shows the mitigation actions planned or already completed to reduce the probability or consequence of the risk occurring:

[9] Risk probabilities, and impacts on each objective, were given ratings of 1 (low) to 5 (high). The product of the risk probability and highest risk impact determined the risk level.

Table 3.3

Risk	Consequence	Rating Before Mitigation	Mitigation	Rating After Mitigation
The Contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR)	Unexpected, adverse subsurface conditions could slow tunnel construction and require the Contractor to undertake remedial/extra work resulting in legitimate claims for extra costs and/or schedule extension for differing subsurface conditions (DSC).	High	• The GBR is based on extensive field investigations carried out over a 10-year period and knowledge gained through construction of the existing SAB2 tunnels. • The 3-stage GBR process used facilitates contractor input and concurrence before construction begins. • Residual tunnel construction risk to OPG is addressed by a contingency allowance of $96 million in the Project release estimate and a contingency allowance of 8 months in the scheduled in-service date, both based on a 90% confidence level.	Medium
OPG resources with knowledge and experience required for design and construction of a major tunnel are severely limited.	OPG resource limitations could have significant impacts on Project quality, cost and schedule.	High	• OPG has engaged Hatch Mott MacDonald, an Ontario based consultant with considerable tunnel design and construction management experience, as Owner’s Representative for this Project. • The design/build contracting approach, engaging internationally experienced tunnelling experts, will provide the necessary engineering and construction expertise.	Low
Queenston Shale, the host rock formation for the majority of the tunnel, has swelling properties when exposed to fresh water.	Swelling of the Queenston Shale surrounding the tunnel could over-stress the tunnel lining and cause damage that would interrupt flow through the tunnel and require expensive remedial work.	High	• Because this kind of damage could take decades to develop, penalties, warranties or holdbacks are impractical. Instead this risk is being mitigated through conservative, mandatory engineering specifications for aspects of the tunnel design related to rock swelling.	Low
Design/ Performance	The constructed tunnel may not meet design/performance	High	• Mandatory design requirements established	Low

Risk	Consequence	Rating Before Mitigation	Mitigation	Rating After Mitigation
criteria not met	criteria such as the guaranteed water flow capacity, accommodation of swelling of the host bedrock, particularly Queenston Shale, or design for a 90-year service life.		by OPG/Hatch Mott MacDonald. • Design Review by an experienced Technical Review Committee. • Design/Build Contract includes liquidated damages for failure to achieve the agreed diversion capacity (Guaranteed Flow Amount) valued to compensate OPG for the reduced energy production throughout the 90-year service life. • Performance/warranty bonds and/or letters of credit provided by the Design/Build Contractor.	
Serious construction accident	There are many safety hazards associated with tunnel construction that need to be identified and appropriately managed (steep grades, slips and falls, falling objects, water hazards, confined space, truck traffic, operating machinery, noise, dust, etc.)	High	• Safety program / performance was a significant factor in contractor pre-qualification • Contractor required to develop and submit an acceptable comprehensive site specific safety plan prior to start of construction activities • Safety accountabilities clearly identified • Site safety monitoring by the Owner's Representative.	Low
Public safety and security	Risk of incidents, accidents and potentially fatalities to unauthorized persons entering the construction site and gaining access to areas and activities having High MRPH hazards.	High	• Contractor to implement an approved site-specific Security, Public Safety & Emergency Response Plan that is consistent with the Niagara Plant Group's managed system. • Site safety monitoring by the Owner's Representative.	Low

The Business Case also included a number of risks that could have an impact primarily on the longer-term business or financial outcomes of the Project:

Table 3.4

Risk	Consequence	Rating Before Mitigation	Mitigation	Rating After Mitigation
Inability of OPG to fully recover the Project costs through the Regulated Rate	Adverse financial impact on OPG	Low	• Demonstrate prudence in managing Project cost through a comprehensive cost control process • Project costs include a contingency allowance which corresponds to a 90% confidence level that the Project will be completed within the estimated costs.	Low
OPG has retained the hydrologic risk (uncertainty regarding Niagara River flow).	Incremental average annual energy output from the SAB complex could be less than 1.6 TWh resulting in a need to increase base load hydroelectric energy rates to recover Project costs.	Medium	• Financial sensitivity analyses demonstrate that the Niagara Tunnel Project remains competitive with future renewable electricity supply options if less water is available throughout the expected service life. • Being part of OPG's regulated hydroelectric assets, the hydrologic risk is expected to be borne by electricity customers through the water variance account.	Low
A successful claim by others in Canada or the United States to use Niagara River water available for power generation that exceeds OPG's capacity.	OPG could lose rights to use some of the Niagara River water available for power generation.	Medium	• Under the terms of the Niagara Exchange Agreement, the Niagara Parks Commission provided covenants securing the assurance of NPC that it would grant water rights to no party other than OPG. • Complete the new tunnel so OPG has adequate facilities to utilize Canada's entitlement to water available for power generation to reduce the risk of a claim by others to unused water.	Low
The 1950 Niagara Diversion Treaty is now subject to renegotiation following a 1-year notice period.	The government in either Canada or the United States could pursue renegotiation of the 1950 Treaty to address issues raised by other stakeholders that could result in a reduction of flow available to OPG for power generation at the SAB complex.	Low	• No mitigation possible.	Low

3.4.2 Quantitative Risk Assessment

In addition to the qualitative risk assessment, quantitative risk assessments using the Monte Carlo simulation technique were also performed. The resulting cost and schedule contingencies were selected to bring the confidence in the estimate and schedule to the 90% level[10]. The original $985 million approved budget therefore included a contingency of $112 million primarily to cover the subsurface conditions risk. In addition, an eight-month schedule contingency was added onto the contractual Substantial Completion date of October 2009, bringing the original committed in-service date to June 30, 2010.

3.5 Superseding Business Case

During the first year of tunnel construction, the progress of tunnel excavation by Strabag was much slower than had been expected. Initial delays were caused by start-up problems with the TBM. As work progressed into 2007, there was significant overbreak in the tunnel crown within the Queenston Shale formation, which made it difficult to excavate and support some parts of the tunnel. In accordance with the mechanism provided in the Design-Build Agreement with the Contractor, a Dispute Review Board (DRB) hearing in 2008 reviewed the actual subsurface conditions compared to those that were anticipated and included as part of the DBA. The DRB concluded that Differing Subsurface Conditions had, in fact, been encountered. After an assessment of its options, and based on the DRB recommendations, OPG renegotiated the original DBA with Strabag into a “target cost/target schedule” contract called the Amended Design-Build Agreement (ADBA) which is described in more detail in Section 4.4.5.

A Superseding Business Case for approval of a revised total Project cost estimate of $1.6 billion and revised completion date of December 2013, based on the ADBA, was prepared and submitted to the OPG Board of Directors in May 2009. Upon Board approval, the ADBA, with an effective date of December 1, 2008, was executed in June 2009. It should be noted that the Contractor continued with tunnel mining throughout this entire period.

3.5.1 Alternatives Considered

The Superseding Business Case outlined four alternatives going forward:

Status Quo - Proceed Under the Existing DBA (Not Recommended)

This alternative entailed a high risk that Strabag would abandon the Project due to the lack of certainty over reimbursement for the delays and costs[11] already incurred, the anticipated continuing difficulties in boring through the Queenston Shale, and expected liquidated damages costs. It was considered highly probable that this alternative would have resulted in a need to have the tunnel completed by another contractor at

[10] That is, the contingencies were chosen such that when they were included there would be a 90% probability that the project cost would be under the approved estimate and would be in-service within the approved target date.

[11] Strabag had estimated that it had lost $90 million to that point in the project.

additional and unknown cost and with further delays. Also OPG could have expected to incur additional costs for legal proceedings. This alternative was not recommended.

Alternative 1- Proceed Under a Target Cost Amended DBA (Preferred Alternative)
The Dispute Review Board had recommended in August 2008 that OPG and Strabag should "equitably" share the cost and schedule impacts. For this alternative the tunnel would be completed under the amended DBA that had been negotiated to include a target cost and target schedule as well as cost and schedule performance incentives and disincentives. Tunnel alignment would be changed as recommended by Strabag to minimize further excavation in the Queenston Shale formation. This alternative also included a new risk sharing mechanism, as well as settlement of the Contractor's outstanding claims to November 30, 2008. The remaining cost for this alternative was estimated to be $1,137 million for a total Project cost of $1,600 million. Overall, this was expected to be the lowest cost alternative for completion of the tunnel.

Alternative 2 - Engage another Contractor to Complete the Project (Not Recommended)
This alternative would have involved terminating the existing DBA with Strabag and engaging another contractor to complete the tunnel. It was expected that this alternative would result in a further delay of 18 to 24 months while another contractor was engaged[12] and work restarted. Experience gained by Strabag to date would have been lost. In addition, there would have been additional and difficult to predict costs, including those related to legal proceedings to recover damages from Strabag.

Alternative 3 - Cancel the Project (Not Recommended)
It was estimated that the cost of abandoning the Project would have been approximately $100 million in order to secure the site in a safe and environmentally acceptable state. It was also expected that there would have been a low likelihood of recovering any of the $463 million already spent through the regulated rates. The opportunity to generate 1.6 TWh per year of renewable energy from the SAB plants would have been lost.

3.5.2 Financial Analysis

Despite the significant increase in the Project cost estimate and the expected delay in the in-service date, the financial analysis of the recommended alternative still showed that it would be worthwhile to complete the tunnel as a regulated hydroelectric asset, provided that the additional costs would be recoverable. The following table, included in the Superseding Business Case, shows the comparative economics of the original versus the superseding release:

[12] At the time of the Superseding Business Case, a somewhat similar situation had occurred on the Seymour Capilano twin water tunnel project in Vancouver. The original contract had recently been terminated over a dispute regarding subsurface conditions. Engaging a new contractor and restarting that project took over a year and the project cost increased substantially.

Table 3.5

Financial Measure	Original Approval July 28, 2005		Superseding Release May 21, 2009	
		In 2009$		In 2009$
LUEC (¢/kWh)	4.8 (2005$)	5.2	6.8 (2009$)	6.8
Equivalent PPA (¢/kWh)	6.7 (2011$)	6.7	9.5 (2014$)	9.4
Revenue Requirements (¢/kWh)	5.8 (2011$)	5.6	8.7 (2014$)	7.9
Revenue Requirements Post Gross Revenue Charge Holiday (¢/kWh)	9.4 (2021$)	7.4	13.0 (2025$)	9.5

At the time of the superseding release, the Feed-In-Tariff (FIT) under the Green Energy Act for hydroelectric projects under 50 MW was 12.2 ¢/kWh. This program was deemed comparable to the "PPA" measure included in the above table, which had been used in the original Business Case, except that a FIT contract was for 40 years rather than the 50 years assumed in the equivalent PPA calculation. With the Niagara Tunnel completed at the higher cost and placed in-service in 2013, the overall revenue requirement for OPG's regulated hydroelectric assets was expected to increase from 4.0 ¢/kWh to 4.4 ¢/kWh (2014$). A financial sensitivity analysis indicated that a going forward Project cost increase of $100 million, or a six-month Project delay, would each result in an increased revenue requirement of $0.5 ¢/kWh (2014$).

Table 3.5.1 below provides the actual results for the financial measures:

Table 3.5.1

Financial Measure	Final	
		In 2009$
LUEC (¢/kWh)		6.6
Equivalent PPA (¢/kWh)	9.3 (2014$)	9.1
Revenue Requirements (¢/kWh)	8.8 (2014$)	7.9
Revenue Requirements Post Gross Revenue Charge Holiday (¢/kWh)	10.8 (2025$)	7.9

3.5.3 Risk Analysis

As part of the re-planning related to the renegotiated tunnel contract, OPG's Risk Services Group conducted several quantitative risk analysis workshops in March 2009. OPG Project team and OR representatives were asked to provide individual estimates of both the likelihood and the impact of 13 "key risks" that they had previously identified. These risks included the Major Risk Events delineated in the ADBA. Six schedule uncertainty risks (TBM mining, invert concreting, infill shotcreting, arch concreting, contact grouting and pre-stress grouting) were also similarly assessed. Through a Monte Carlo analysis of these risks, it was concluded that a cost contingency of $164 million (which was included in the $1.6 billion superseding authorization) would be sufficient to cover the costs of these risks at a 90% confidence level. The revised in-service date of December 31, 2013 included a 6.5-month schedule contingency beyond the ADBA contractual Target Schedule date of June 15, 2013. This schedule contingency was based on management judgement.

4 Project Management

4.1 Planning Process

In 2004, a core OPG team under the leadership of an OPG Vice President Special Projects (the initial Project Director) was created to oversee the Niagara Tunnel Project. Prior work on the tunnel project throughout the previous decade had already established a conceptual design and routing for the tunnel, developed necessary geotechnical data, and obtained environmental approval. Therefore, a full "concept/feasibility" phase for the Project was not required and it could move directly into Project definition. Accordingly, the NTP was to be divided into two main phases:

- **Phase 1 - Planning and Procurement Phase** – including all work leading up to approval for Project execution by the OPG Board of Directors; and
- **Phase 2 – Execution Phase** – including all design, construction and commissioning work for the tunnel and related facilities through to Project closeout.

Because of their prior involvement with and knowledge of the Project, Hatch Mott MacDonald (HMM) was retained in July of 2004 to be the Owner's Representative (OR) for Phase 1. The OR would undertake most of the detailed project planning, as well as develop the technical specifications and oversee the design-build contractor selection process, under the direction of the OPG Project Director and team.

At the request of the Project Director, a Project Definition Rating Index (PDRI) [13] assessment was conducted on October 1, 2004. This assessment was intended to help identify those aspects of Project definition that would require further work as part of the overall Project front end planning process[14]. The PDRI review, which resulted in a score of 308, showed that there were still a number of planning gaps, most notably lack of clear definition of the business drivers and Project objectives, a need to further define the Project delivery strategy, and a need to conduct the Project risk analysis.

[13]. The PDRI is a pre-project planning tool, developed by the Construction Industry Institute (CII) that can be used as a predictor of project success. It measures project readiness to proceed based on the assessment of approximately 70 project planning elements. An overall measure is calculated, on a 0 – 1000 scale, where a *lower* score is better. A score of 200 or less at the time of authorization has been correlated through CII research with a higher probability of meeting cost and schedule targets.

[14] Although the most common use of the PDRI is to assess the level of project definition just prior to the request for authorization, it can also be a valuable tool to help define work scope early in the front end planning phases of a project.

During 2004, HMM also started development of a draft Project Execution Plan (PEP). In early March 2005, a facilitated workshop[15] was held with the OPG/OR Project team to review the draft PEP. One other important focus of this workshop was to clarify the roles and responsibilities of the team members to ensure they were understood and agreed to. Some team members were also given a lead role in further preparation of sections of the PEP. Following this workshop, a new draft of the PEP was issued, reviewed by the team and then, with agreed changes, formalized as Revision 0 of the PEP in April 2005. All team members signed off on the PEP to acknowledge their participation in its creation.

In April 2005, a second PDRI assessment was done in preparation for the request for Project authorization by the OPG Board. Some elements of the Project still could not be completely defined until the Design-Build contract was in place, but reasonable assumptions were made based on OPG/OR team knowledge of the Project. The PDRI review resulted in a score of 115. The gaps from the earlier PDRI had all been addressed to the fullest extent possible.

With the issue of Revision 0 of the PEP and completion of the PDRI, two of the conditions mandated by the project management governance as being essential for Project release had been fulfilled. In parallel with the project management planning, the Release Quality Estimate and the financial modeling/analysis for the Business Case were also completed. The financial model was independently reviewed and verified by Access Capital for the OPG Major Projects Committee.

Following Board approval of the Project in July 2005, a second agreement was signed with HMM in September 2005 to have them undertake the OR/project management role for Phase 2 of the NTP.

In preparation for the start of project execution, a Memorandum of Understanding (MOU) was created between the Niagara Plant Group (the ultimate customer for the Project) and the OPG/OR Project team[16]. The MOU defined constraints governing how the Project would be executed, including those required to minimize the impact on NPG ongoing operations. It also defined the role of NPG in Project activities such as design reviews, safety and security management, emergency management, stakeholder relations, outage planning, etc. Development of the MOU started in October 2005 and the final document was signed off in February 2006. Amendments to the MOU were later issued in November 2010 – to document additional land to be used by the Project – and in June 2011 to include some emergency and non-emergency protocols.

[15] This workshop was also intended as a team-building exercise for OPG and consultants participants in the project.

[16] The MOU mechanism had been successfully used on past projects, such as the Lambton Rehabilitation Project, to improve communication and cooperation between the plant customer and an external project team.

Revision 1 of the PEP was issued in March 2006, after the Design-Build contract had been awarded and more details concerning the execution approach, including the technical design basis as well as the planned timing and sequence of activities, were known. Further revisions of the PEP were issued in March 2006, September 2010, and January 2013, in accordance with project management governance requiring new revisions to reflect any significant changes in the Project planning baseline. All revisions to the PEP were also signed off by the full Project team.

A Project Policies and Procedures Manual was developed by HMM to guide implementation of the Project Execution Plan. This manual provided more detailed instructions, primarily to OR staff, on how certain aspects of the PEP, such as project cost and schedule controls, engineering management, safety and environmental management, and construction oversight would be carried out. The procedures were periodically revised and reissued throughout the Project.

4.2 Objectives

In addition to the fundamental business objective listed in Section 3.1, more specific Project objectives, as stated in the Project Charter of January 2005, and expanded in subsequent versions of the Project Execution Plan, were defined as listed below:

Table 4.1

Objective	Measures
Maintain a safe working environment	Complete the Project with zero fatalities, zero critical injuries, and zero lost time injuries while maintaining the safety of the public at all times
Meet all environmental and mitigation requirements	Meet the commitments contained in the Environmental Assessment (EA) and the conditions of the EA Approval, all legislated environmental and mitigation requirements and provide, at Project completion, minimal long-term environmental obligations to the OPG Niagara Plant Group
Maintain the Project on schedule and within budget	The Project was to be maintained within the approved schedule and budget. Decisions regarding any deviation from approved budget and/or schedule would be based on the net business impact, considering the tradeoff between Project cost and business revenue.
Achieve a high overall quality of design and construction, meeting performance requirements	It was intended that the design and construction of the Project provide for a 90-year service life for key elements of the facility such as the tunnel, intake structure and outlet structure, and would not result in

	any forced outages during that period. Other components of the Project would be designed and constructed to meet existing legal requirements. The contract would require the tunnel contractor to specify and meet a measured flow through the tunnel at completion. This was established as 500 m^3/s.
Maintain a good working relationship with stakeholders, contractors and the affected public.	Priority would be given to maintaining good working relationships with stakeholders, contractors, and the affected public during planning and construction of the Project. A key objective was to minimize Project impact on the ongoing operations of Niagara Plant Group. Measures of this objective included: • Zero Treaty violations concerning Falls flow • Zero International Niagara Board of Control (INBC) Directive violations concerning Grass Island Pool (GIP) operation • Zero ice management incidents • Zero forced outages at existing diversion and generation facilities • Optimal planned outages coordinated with Niagara Plant Group outage plans • Maintenance of positive relationships with regulators and host communities • Maintenance of ISO 14001 registration • Maintenance of BSA 18000 registration. • Minimize ongoing (post-Project) monitoring requirements by NPG
Ensure sufficiently detailed reporting to the OPG Board of Directors and the Province of Ontario such that their confidence in OPG's ability to execute large projects was maintained.	No specific measures or targets were defined for this objective.

4.3 Scope

As noted earlier, the NTP was divided into two phases:

Phase 1 – Planning and Procurement

Key deliverables for the phase leading up to full Project authorization included tunnel contract bidder pre-qualification, contractor selection, executed Design-Build contract, essential permit and approval submissions, third party agreements, designs for enabling work, a Release Quality Estimate (RQE), and Business Case development and submission for Phase 2 approval by OPG's Board of Directors.

Phase 2 - Execution

Key deliverables included: the completion of permits and approvals; detailed design and construction of the diversion tunnel and associated facilities; tunnel commissioning and placing into service; performance testing; and Project closeout including a closeout report and transfer of permanent records to OPG/NPG.

The Project scope was made up of the following elements:

4.3.1 Third Party Requirements

Third party requirements included: the work necessary to meet the conditions of the EA approval; pre-construction permitting; communication with the public; adherence to the Community Impact Agreement between OPG and local municipalities; and adherence to the MOU with the Niagara Plant Group.

4.3.2 Tunnel Contract

Establishment of the Design-Build contract included: the prequalification of potential bidders; development of the contract terms and conditions; development of technical specifications including the Owners Mandatory Requirements; establishment of an agreed Geotechnical Baseline Report with the Contractor; and management of the bidding, evaluation and negotiation process up to selection of the preferred contractor. The formal contract agreement would be signed after Project approval by the OPG Board of Directors and when Project financing was in place.

4.3.3 Tunnel and Facilities Construction

Construction of the tunnel was done using a tunnel boring machine (TBM). The direction of tunneling was from the outlet to the inlet, and the original route generally followed the line of the two existing tunnels, under the City of Niagara Falls.

4.3.3.1 Intake Area

The Intake Area work upstream of Niagara Falls included:

- Setting up the Contractor's lay down area, shops and offices using available space along the Niagara Parkway;
- Creation of a new separate access road out to Portage Road;

- Installation of temporary traffic signals on the Niagara Parkway at Portage Road to minimize impacts on through traffic during construction; and
- In-water excavation of the intake channel, installation and removal of a cofferdam, removal of the existing ice accelerating wall and construction of a new wall, closure of the downstream Bay 1, and construction of portions of the intake approach wall.

4.3.3.2 Intake Structure

This work included design and construction of a reinforced concrete intake structure underneath the INCW, upstream of the Falls. The new structure can house the service gates for closure of the tunnel at the upstream end. The tunnel can be isolated from the upper Niagara River for dewatering by installing the sectional steel intake gates in steel guides embedded in the intake structure. Removable steel guide towers are provided to enable the gate sections to be installed by a mobile crane.

A cofferdam had to be constructed to allow for the intake excavation. Prior to cofferdam construction, a new accelerating wall, used for ice management at the intake, was constructed and the existing accelerating wall demolished and removed. The cofferdam was removed after completion of the intake works and removal of the TBM.

Work at the intake also included grouting of the rock formations above the tunnel entrance to minimize water inflows into the tunnel during the TBM drive through these formations. In addition, underwater excavation of an intake channel was required upstream from the intake structure and beyond the confines of the cofferdam.

4.3.3.3 Diversion Tunnel

The tunnel was excavated using a 14.44 m diameter open gripper TBM manufactured by the Robbins Company. The TBM was shipped in parts and assembled for the first time at the NTP site. Excavation started at the tunnel outlet (SAB) end. The tunnel was originally to be constructed in two passes with the first pass consisting of tunnel boring followed by erection of an initial lining consisting of shotcrete, mesh, bolts and ribs[17] to support the excavation. Once the complete tunnel was excavated and the TBM removed, a cast-in-place concrete final lining between 600 and 700 mm thick would be constructed. This plan was later modified so that construction of the final liner proceeded concurrently with and behind the tunnel boring. The invert (lower part) of the lining was installed first, followed by the arch, or upper section, of the lining. To avoid water leakage[18] into the surrounding rock formations, an impermeable polyolefin

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[17] Strabag's initial plan to use a ring erector to install steel reinforcing rings as part of the initial support structure as the tunneling progressed was abandoned early in the tunnel drive due to their inability to get the ring erector equipment to work properly.

[18] The design had to prevent contact of fresh water from the tunnel with the surrounding shales. Otherwise there would be swelling of the rock surrounding the tunnel which would lead to unacceptably high stresses on the structure.

membrane was installed between the initial shotcrete and final concrete lining to ensure watertightness of the tunnel. The final lining was prestressed using high-pressure grout injected between the impermeable membrane and the initial lining.

Dewatering shafts were constructed at the low point of the tunnel to permit future inspection or maintenance, if required.

Because of the difficulties and delays encountered in safely excavating and supporting the section of tunnel in the Queenston Shale formation, part of the tunnel was rerouted midway through the Project to minimize the length passing through the Queenston Shale. To allow for this upward vertical realignment out of the Queenston Shale, the horizontal alignment was shifted about 200 m eastward, directly below Stanley Avenue and out from under the two existing tunnels. This also shortened the tunnel length by about 200 m to 10.2 km.

On completion of the tunnel, an independent third party performed a flow test to establish whether the tunnel met the flow guarantee. The Design-Build contract terms included liquidated damages or bonuses based on the measured flow versus the guarantee.

4.3.3.4 Outlet Area

The main construction facilities were at the tunnel outlet end on OPG's property, between the PGS Reservoir and the existing SAB2 canal. A new road connection to Stanley Avenue was constructed. The Regional Municipality of Niagara installed temporary traffic signals at the intersection with Stanley Avenue on behalf of OPG.

4.3.3.5 Outlet Structure and Channel

The outlet channel was excavated using drill and blast methods. This channel was initially used as the TBM staging and assembly area. Connecting the channel to the tunnel is a reinforced concrete structure, housing a vertical lift gate for closure of the tunnel. The lift gate has five articulated structural steel sections running on steel wheels bearing on steel roller paths embedded in the concrete structure. The inlet structure also has provision for installation of sectional service gates downstream of the lift gate. A surge shaft in the transition from the tunnel to the outlet is designed to contain any surge that occurs during outlet gate closure under flowing water conditions, and also provides access for inspection when the tunnel has been dewatered. Water from the diversion tunnel discharges through the excavated channel into the existing canal system feeding the SAB complex. The PGS Dewatering Structure was also removed and services (e.g. power cables, water main) that had been on the structure were re-routed.

4.3.4 Enabling Activities and Miscellaneous Construction

A number of enabling activities had to be performed before the start of the tunnel work:

- Establishing expropriation rights to the tunnel route as allowed under Bill 100, *Electricity Restructuring Act*, Section 51;
- Conducting land surveys to determine the location of property required for the tunnel;
- Expropriating subsurface rights to privately owned property, and notifying owners;
- Expropriating subsurface property rights from the City of Niagara Falls and the Regional Municipality of Niagara. The majority of these properties consisted of road crossings;
- Acquiring, through negotiated agreements, the necessary surface and subsurface property rights from the Niagara Parks Commission;
- Acquiring, by negotiated agreement, the necessary subsurface rights to the underground crossing of railway corridors owned by Canadian National and Canadian Pacific Railways. OPG did not have the right to expropriate these properties;
- Completion of various access road improvements and utility relocates at the inlet and outlet areas. The Regional Municipality of Niagara (RMON) carried out the roadwork on behalf of OPG under the Community Impact Agreement; and
- Surveying a number of structures near the site before the start of construction to establish a basis for determining if the structures had been affected by the construction activities such as blasting, and to determine responsibility for repair, if necessary. OPG/NPG and the Contractor were required to endorse the preconstruction survey before the start of construction activities that could result in damage to the existing SAB, PGS or INCW facilities.

Prior to contract completion, post construction work included decommissioning of temporary gas, electrical, telecom, and sewer connections installed for construction of the tunnel.

4.3.5 Project Management

Management of the Project was a combined responsibility of OPG and the OR working together as a team, under the authority the OPG Project Director. Most of the Project management team members, including the Project Manager, were supplied by the OR. A detailed Responsibility Matrix was used to assign the specific project management task responsibilities.

4.3.6 Exclusions

Specifically excluded from the Project scope were:

- Dewatering pumps for the tunnel;

- Sectional service gates at the outlet; and
- Permanent closure of the adit excavated in the 1990s for geotechnical investigations related to SAB3 development.

4.4 Project Delivery Strategies

4.4.1 Owner's Representative

At the time the Project was restarted in 2004, it was recognized that OPG did not have the technical capability or staff to manage a tunnelling project of the magnitude of the NTP. Therefore, as is common with projects of this type, OPG decided to retain an Owner's Representative (OR) to provide project management services as well as detailed oversight of the engineering, construction and commissioning of the tunnel. The OR services were initially procured in July 2004 for Phase 1 and a subsequent agreement in September 2005 extended the services to cover Phase 2 of the Project. An amendment to the OR contract was executed in January 2010 to reflect the new Amended Design-Build Agreement with the Contractor and to extend the duration and cost of the OR services to a new final completion date of December 31, 2013.

The OR services were provided by Hatch Mott MacDonald in association with Hatch Acres (HMM). OPG chose HMM to be the OR on a sole source basis for the following reasons:

- Hatch Mott MacDonald had recognized expertise in tunneling;
- Hatch, working with Acres Bechtel, had acted as the OR when the Project was under development in 1998 and OPG had been pleased with Hatch's performance;
- Acres, which was purchased by Hatch in June 2004, had provided engineering support on the proposed SAB 3 and the tunnel design since 1991;
- The sub-surface risks of this Project had been investigated and analyzed by Acres and Hatch. As a result, Hatch had considerable prior knowledge about the Project, including the geological risks; and
- Hatch is Canadian owned and headquartered in Mississauga, giving OPG convenient access to senior Hatch staff. The contract specifically named the individual who would be the HMM Project Manager, with provisions for OPG approval of any replacement.

The OR led or participated in all aspects of the Phase 1 (Planning and Procurement) work including:

- Identification and pre-qualification of bidders;
- Development of the RFP documents including the Owner's Mandatory Requirements, Geotechnical Baseline Report, commercial terms, etc.;
- Preparation of proposal evaluation criteria;
- Bid evaluation coordination;
- Negotiation with proponents and finalization of the DBA with the selected Contractor;
- Development of permitting submissions required prior to Project authorization
- Preparation of the Project Execution Plan and Release Quality Estimate.

In Phase 2 (Execution) the OR provided:

- Oversight and monitoring of engineering design and construction on behalf of OPG ;
- Contractor drawing and data submittal reviews[19];
- Full time, on-site quality oversight of tunnel construction against Project drawings, specifications and installation plans ;
- Recording of the Contractor's daily work activities and progress;
- Contractor quality audits;
- Health and safety oversight, monitoring and auditing where the Contractor was the Constructor under the OHSA;
- Health and safety management on behalf of OPG, where OPG was the Constructor for the Intake Part Project;
- Environmental management oversight of the Contractor;
- Additional engineering studies or investigations, where required, either directly or through subcontractors;
- Project cost and schedule controls;
- Weekly and monthly Project reporting;
- Review of the Contractor's applications for progress payments prior to submittal to OPG; and
- Assistance to OPG in the negotiation of the Amended Design-Build Agreement.

4.4.2 Design-Build Agreement

For major engineering and construction projects, the two most common delivery strategies are Design-Bid-Build and Design-Build. The Design-Bid-Build approach

[19] Some detailed designs were also reviewed by OPG/ NPG/ Hydro Engineering, specifically those pertaining to intake and outlet gates, hoists and associated mechanical, electrical and control systems, including operation, maintenance and handling aspects.

involves having the owner (often with the assistance of a consultant) first prepare detailed design and construction specifications and then, usually through a competitive tendering process, retain a construction firm to build the facility to the pre-established design. Under Design-Build, the owner contracts with a single entity to design and construct the facility to meet its pre-established requirements. OPG had previously started to use the Design-Build approach in the 1998-1999 RFP process for design and construction of the tunnel. This method was again chosen in order to:

- Reduce project management complexity by providing OPG with single-point accountability through the Contractor for all aspects of Project design and construction, including much of the permitting;
- Minimize Project duration, by eliminating the need to contract sequentially for design and construction services;
- Take advantage of the design and construction expertise of contractors specializing in tunnelling work;
- Fully integrate constructability considerations into the design;
- Appropriately allocate Project risks; and
- Obtain as much upfront price certainty as possible.

In order to ensure that the tunnel would meet OPG's long-term needs and commitments, a set of "Owner's Mandatory Requirements" formed the basis of the specifications in the Request for Proposals and the subsequent Design-Build Agreement (DBA). This document was essentially a functional and performance specification describing key technical parameters of the facility such as required flow rate, tunnel service life, and essential technical standards to be met, as well as known constraints such as the need to use a TBM to meet the EA approval conditions. The RFP requested proponents to prepare a proposal conforming to these mandatory requirements but reflecting their own knowledge and experience in tunnel construction.

Four pre-qualified firms were invited to bid, and proposals were received from three consortiums:

- Niagara Tunnel Constructors made up of Hochtief, Aecon, and Vinci with engineering by Hochtief & Klohn Crippen;
- Niagara Tunnelers made up of Obayashi and Kenaidan with engineering by Jacobs, Black & Veatch and Golder Associates; and
- Strabag AG made up of Strabag, with Dufferin as a subcontractor for all the non-tunnel works such as the inlet and outlet structures, and engineering by ILF and Morrison Hershfield.

Strabag, the successful bidder, also had a number of subcontractors for equipment supply, including:

- The Robbins Company (USA) for design, manufacture and delivery of the TBM;

- ROWA (Switzerland) for design, manufacture and supply of the TBM trailing gear and equipment; and
- BMTI/Baystag (Austria/Germany) for design, manufacture and supply of the main structural components for the invert and arch carriers and shutters. Baystag provided the design for the restoration carriers[20] with manufacture and supply of the main structural components by Burnco (Markham, ON).

In addition to having a competitive price, Strabag was selected on the basis of having what was judged to be a technically superior proposal for providing an impervious tunnel lining that would prevent water leakage into the surrounding Queenston Shale. Strabag's TBM supplier also had a TBM main bearing available which would shorten the delivery time for the machine by several months.

The negotiated Design-Build Agreement met the single point accountability objective by allowing OPG and the OR to deal with a single entity (Strabag) that in turn managed all of the other related subcontractors. The subcontractors provided the specialist expertise required to execute various aspects of the total facility Project design and construction such as the intake and outlet channels and structures.

Because the Project had been deferred once before, after the 1999 Request for Proposal process had been initiated, there was concern that potential bidders might be reluctant to go to the trouble and expense of again preparing bids for a Project that had not yet been approved. Therefore it was decided that an honorarium of $600,000 would be paid to each proponent that submitted a proposal but was not the successful bidder. This strategy was instrumental in obtaining the three proposals from the RFP process.

4.4.3 Geotechnical Baseline Report

One of the most significant risk drivers for tunnel construction is the lack of complete knowledge of the subsurface rock conditions along the tunnel route. Geotechnical investigations can, at best, provide only a sample of these conditions. For the NTP there were known concerns, particularly regarding the rock conditions under the buried St. David's Gorge and the high horizontal stresses within the rock of the Queenston Shale formation. Therefore, a significant consideration in the formation of the DBA would be establishing a reasonable basis upon which OPG would assume an acceptable portion of the risk of encountering "Differing Subsurface Conditions" (DSC) during construction.

In order to ensure agreement between OPG and the Contractor on the likely subsurface conditions to be encountered during tunnel construction, a 3-step approach was used:

[20] The restoration carrier was a special piece of equipment used in rebuilding of the tunnel overhead profile where overbreak of the surrounding rock had occurred during tunneling.

1. Results of the extensive previous geotechnical studies conducted by OPG and its consultants[21] were included in the RFP documents in the form of a Geotechnical Baseline Report, designated as "GBR A".
2. The contract proponents were required to prepare and submit with their proposals their own geotechnical assessments, designated as "GBR B".
3. OPG and the successful bidder jointly agreed on a final set of baseline geotechnical conditions, designated as "GBR C", that were intended to form the reference for any claims by the Contractor that the subsurface conditions encountered were more adverse than those expected and documented in GBR C.

The DBA included a Dispute Review Board (DRB) mechanism for reviewing and resolving claims related to the contract. The DRB was comprised of three independent and recognized tunneling experts who were kept informed of the Project progress. The GBR C was intended to provide the basis for assessing Contractor DSC claims, as well as any other claims that could not be resolved by mutual agreement, and deciding on the extent to which OPG or the Contractor would be responsible for additional costs or delays related to such claims.

4.4.4 Contract Price and Schedule

For major construction projects, several compensation approaches are possible, ranging from lowest to highest assumed cost certainty as follows:

- Time and materials (or "cost plus") – lowest up front cost certainty;
- Cost plus fixed fee;
- Unit price;
- Guaranteed maximum price; and
- Firm price (or "lump sum") – highest up front cost certainty.

Selection of the appropriate approach generally reflects the owner's trade-off between the predictability of cost (and schedule) and the degree to which the owner wishes to be directly involved in, or have control over, the project including the ability to make changes during execution. In addition, the extent of up front cost and schedule predictability will be related to the level of scope definition, design completion and knowledge of project conditions at the time the contract is formed. The overall objective in selecting a delivery strategy and compensation approach is to try to appropriately allocate the project risks to the parties best able to manage them, thereby resulting in the optimum price/cost for each party.

For the NTP a fixed price approach was initially chosen for the original DBA, although as is common in large construction projects, provisions were made in the contract for

[21] Most of these studies had been carried out during conceptual phase investigations for the proposed SAB 3 between 1983 and 1989. Further work was subsequently done for the definition phase between 1991 and 1993 and again from 1994 to 1996. All of these investigations were documented in a 12 volume Geotechnical Data Report that was made available to the tunnel project proponents prior to proposal submission and formed the basis of the GBR A.

possible price changes due to approved changes (Project Change Directives). The overall intent of the fixed price approach was to provide as much up front cost certainty as possible, with the residual cost risk being addressed by OPG's Project contingency. Under a fixed price arrangement, the Contractor's actual costs would not be available to OPG, and monthly payments were to be made against Project completion percentages according to a cost breakdown in the contract, as verified by the OR.

To establish higher schedule certainty, the contract included a required Substantial Completion Date, with bonuses for early completion and liquidated damages to compensate OPG for any delays. The residual schedule risk was addressed by building a schedule contingency into the OPG Project plan.

4.4.5 Amended Design-Build Agreement (ADBA)

In May 2007, as the TBM mining had advanced approximately 840 m to the top layer of the Queenston Shale, a large rock block fell and damaged the TBM. Tunnelling was stopped for more than three weeks, while the rock was removed and the damage repaired. As a result, Strabag filed a claim (Project Change Notice 17) for Differing Subsurface Conditions. Throughout the next several months, progress continued to be very slow due to extensive overbreak and the need to install spiles ahead of the TBM to provide rock support during tunnelling. Tunnelling productivity was approximately 25% of the original estimate and the Contractor was forecasting a significant delay in the tunnel completion date. In the fall of 2007, Strabag requested that OPG consider allowing a change in tunnel alignment to enable the TBM to move out of the Queenston Shale formation earlier[22]. After many discussions between OPG and Strabag, a decision was mutually made in early 2008 to take the as-yet unresolved PCN17 claim, as well as other DSC issues[23], to the DRB. Two days of hearings were held with the DRB in June 2008, during which OPG and Strabag presented their positions regarding the dispute. The DRB decision was issued in August 2008. The DRB upheld Strabag's claims regarding excessive overbreak and the inadequacy of the table of rock conditions in the GBR, while accepting OPG's positions on the other issues. Two key DRB recommendations were that:

"… the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible."

and

[22] Since the original tunnel route was directly under the existing SAB tunnels, a horizontal realignment in an easterly direction was necessary to allow the tunnel vertical alignment to be changed to a higher elevation. This also shortened the tunnel by 200 m.

[23] These issues included large block failures, ground conditions under the St. David's Gorge, insufficient stand-up time, excessive overbreak and inadequate table of rock conditions and characteristics.

"… that the Parties jointly revise the Table of Rock Conditions and Rock Characteristics in such a manner that it describes the rock characteristics to be assumed in terms that are mappable (or otherwise quantifiable) so that it can serve as a clear basis for defining DSCs throughout the remainder of the tunnel excavation."

After consideration of the alternatives available (see section 3.5.1), OPG decided to renegotiate the contract with Strabag and develop an Amended Design-Build Agreement. Initially Strabag proposed two options for this:

- *Option A*: Continue with the "fixed price" DBA with cost adjustments for measures needed to deal with the expected rock conditions going forward including rock support provisions for dealing with overbreak, tunnel profile restoration, modifications to the TBM, as well as extension of the Project schedule, and settlement of pending claims. This option also would eliminate or modify the liquidated damages for delay and early completion bonus provisions in the contract. Strabag estimated that their total contract price for the tunnel would increase from the original $622.6 million to $910 million under this scenario.
- *Option B*: Convert the fixed price contract to a target price/schedule contract with cost savings and benefits from early completion (relative to a new target date) to be shared equally between Strabag and OPG. An included overhead fee, proposed initially by Strabag to be 12%, would be decreased to zero if the contract cost reached $1 billion or the Project was six months later than the new committed completion date. The expected contract price for this option would be $856 million.

After internal discussions within OPG and with the OR, and consideration of Strabag's proposed options, a decision was made by OPG to pursue renegotiation of the agreement with the following provisions:

- A lump sum payment to be made by OPG to settle Strabag's costs and claims to November 30, 2008;
- A revised contract, to be effective as of December 1, 2008, and to include a negotiated target price and schedule (similar to Strabag's option B); and
- Incentives and disincentives in the amended contract to ensure completion of the work.

With Strabag's concurrence, a multi-step process was adopted to develop the amended agreement. This included:

- Creation of a set of "Principles of Agreement" between OPG and Strabag; this included a commitment by OPG to settle the outstanding claims [24];
- Negotiation of a Term Sheet reflecting the Principles of Agreement;
- Negotiation of a Memorandum of Understanding establishing the target schedule and a second MOU establishing the target cost; and
- Negotiation of necessary contract changes to convert the original DBA to a target cost agreement.

This approach provided enough financial certainty to Strabag to allow construction of the tunnel to continue without interruption while final details of the ADBA were worked out. The ADBA was signed in June 2009 but made effective as of December 1, 2008. At this point, the tunnel drive was approximately 50% complete.

In the ADBA OPG and Strabag agreed on a target cost of $985 million, a target Substantial Completion date of June 15, 2013 and changes to the allocation of risk. Strabag would be entitled to its "Allowed Costs[25]", plus a 5% overhead recovery fee, to complete the Project. In addition, Strabag would be paid an Interim Completion Fee of $10 million upon completion of TBM mining activities and $10 million upon achieving Substantial Completion. Under the ADBA, Strabag's actual tunnel construction costs were "open book", i.e. subject to verification and audit by OPG and the OR.

The agreement included a cost performance incentive/disincentive of 50% of the difference between Strabag's actual cost[26] and the target cost, as adjusted for approved changes. The ADBA also included a schedule performance incentive of $200,000 per day for each day that Substantial Completion occurred before the target date of June 15, 2013 (again as adjusted for approved changes) and a disincentive of $67,000 per day that the Substantial Completion date went beyond the target date. The aggregate limits of the incentives and disincentives were to be $40 million and $20 million respectively.

The ADBA provided a detailed mechanism for adjustment to the target cost and schedule due to various causes such as OPG requested changes, force majeure events, changes in the law, etc. In addition, should any of nine "Major Risk Events" (such as

[24] Strabag had claimed losses of $90 million. OPG agreed to pay Strabag $40 million to resolve all issues to November 30, 2008 as an effort to share the losses. As a good faith gesture, OPG committed to make the payment within 15 days of signing the principles; however, Strabag was required to provide a $40 million letter of credit in case a final agreement was not reached. OPG also had the right to audit Strabag's losses and to the extent that the $90 million was not substantiated in the audit, the $40 million payment could be reduced proportionately.

[25] "Allowed Costs" did not include such items as head office costs, interest costs, certain insurance deductibles, costs for warranty work, costs to correct or remove a defective part of the project, and third party liability.

[26] The ADBA defined Actual Cost as the $302M paid to Strabag prior to December 1, 2008 plus the accumulated Allowed Costs from December 1, 2008 onwards, minus any proceeds from the sale of assets and any insurance payments received by Strabag.

TBM main bearing failure) occur, the ADBA defined a pre-determined allowed cost or schedule impact, set out in a "Major Risk Table" which formed part of the agreement. The Dispute Review Board from the original contract was replaced by a Steering Committee of senior OPG and Contractor executives to initially consider any disputes. If this committee could not reach agreement, the contract allowed for arbitration as the next step for resolution.

The ADBA, with three subsequent amendments (June 29, 2012, October 16, 2013 and February 3, 2014), remained in effect for the remainder of the Project.

4.4.6 Team Building

OPG's Project leadership recognized at the outset of the Project that there was a need to establish shared objectives and commitments and to build trust between the various parties participating in the Project. Therefore, an initial team building meeting was held between the OR staff and OPG in early 2005 to establish Project goals and to discuss responsibilities for specific aspects of the project planning and procurement phase work.

The DBA also contained a provision for holding – on a voluntary basis – a team building session with the Contractor. A team building session was held with key staff of OPG, the OR and the Contractor in January 2006. The purpose of this session was to improve communication between all parties, and to facilitate problem solving, conflict avoidance and issue resolution. Follow-up workshops, events, and activities were held periodically with Contractor and OPG/OR staff.

4.5 Project Controls

The OR, on behalf of OPG, managed Project schedule and cost controls for all elements of the Project.

4.5.1 Schedule Management

Prior to Project release, the OR had prepared an initial Level 2 critical path schedule using Primavera P3®. After award of the DB contract and receipt of the Contractor's scheduling information, the Contractor's detailed schedule was incorporated into the overall Project P3 schedule to form the Project baseline schedule. Schedules used for Project reporting were displayed in Gantt chart format.

From the outset, the Contractor used two scheduling methods. The aboveground work at the intake and outlet ends, which was executed by Strabag's subcontractors such as Dufferin Construction, was scheduled in Primavera P3®. Strabag itself used the Time/Way diagram method as its primary tool to plan and schedule the underground tunnel boring work and converted the information into P3 for transmittal to the OR and OPG.

Time/Way diagrams, known also as "time-distance" diagrams, are used to plan projects such as roads, pipelines, tunnels, and high-rise buildings, where repetitive work activities can proceed sequentially along a linear path. Activities on the Time/Way diagram, including mining and the various components of waterproofing and liner installation, were plotted graphically along a horizontal distance (chainage) axis, according to their relative linear position, and against a vertical time axis. This allowed showing not only the relative location of the activities but also the direction of progress (e.g. either from the intake or the outlet end of a tunnel) and the planned/actual progress rates. Reading such a diagram along a horizontal (time) coordinate would show the point at which work had been planned or had progressed for each of the sequential activities.

Early versions of the Contractor's P3 schedule were deemed unacceptable by the OR and were returned for revision on several occasions. This was partly due to the use of relatively inexperienced Contractor staff to prepare the initial P3 schedules.

Based on actual progress observed by OR construction management staff on the work site, and monthly progress reports submitted by the Contractor and other Project participants, the OR updated the overall Project schedule each month and calculated a Schedule Performance Index[27] (SPI) for both the tunnel drive and the overall Project using earned value methods.

Early in the tunnel drive, TBM start-up problems delayed the initial rate of progress. As the tunneling proceeded the Contractor encountered rock support problems, including a fall of ground (partial tunnel roof collapse at one location) in May 2007, and progress fell further behind the initial schedule. An early major change in the Contractor's plan was to begin installing the tunnel lining concurrent with and behind TBM mining rather than following completion of the full tunnel drive as had originally been planned. Even with this change, as problems continued, the Contractor's revised schedules showed progressive slippage of the completion date. By September 2007, when the tunnel drive was still only 10% complete, it became clear that the entire Project schedule contingency had been consumed, and the in-service date originally approved by the Board would not be achievable. As part of the negotiation of the Amended Design-Build Agreement, a new schedule and a modified approach to scheduling were adopted.

The basis of the new schedule for the ADBA was a revised Time/Way Diagram reflecting expected levels of tunneling productivity through the various rock layers in the modified routing. From this diagram, a new schedule was developed and agreed to by the Contractor, OPG and the OR as the basis of the ADBA. The new schedule included two key dates tied to contractual schedule performance incentives/disincentives:

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[27] SPI = Earned Value/Planned Value, or, Budgeted Cost of Work Performed/Planned Value of Work Performed. It is a measure of schedule efficiency with values ≥ 1 indicating that the project is on or ahead of schedule. Assuming constant productivity going forward, the SPI can be used to forecast overall project duration.

completion of the tunnel drive (i.e. TBM breakthrough); and Substantial Completion (i.e. first operation with full water flow).

Each month, the Contractor would provide to the OR an update of the P3[28] schedule in electronic format showing progress to date, and the projection to completion. Start and completion dates for each activity, as well as any new activities added to the schedule, were also shown. In addition, the Contractor would provide the updated Time/Way diagram used to update the Project schedule. The scheduling information, including the SPI, was included in the detailed monthly progress reports prepared by the OR for OPG Project staff and senior management. The OR was able to develop a method for calculating the SPI directly from the Time/Way diagram.

Prior to March 2010, the SPI was calculated and reported for each major construction activity (e.g. tunnel mining, invert concrete liner, overbreak repair). In March 2010, OPG instructed the OR to provide an "overall" SPI for the entire Project in addition to the individual SPI calculations for each construction component. Initially the overall SPI was based on every Project activity, including office and general costs. However, in a 2010 audit, OPG Internal Audit pointed out that this method could cause the SPI to be distorted by progress on non-critical path items. This would make its value in calculating the final Project duration questionable. In May 2010, as a result of these observations, the progress reporting was modified to report the overall SPI against activities on the Project critical path.

4.5.2 Cost Management

4.5.2.1 Estimating

Costs were estimated and managed by the OR using a hierarchical Cost Breakdown Structure (CBS) that corresponded to the Work Breakdown Structure (WBS) for the Project. Immediately below the highest (overall Project) Level, the Level 2 elements of the WBS/CBS were:

1. OPG costs (e.g. Project management, NPG support)
2. Professional Services costs (OR, risk assessment, land surveying)
3. Third Party costs (e.g. Community Impact Agreement)
4. Miscellaneous construction costs (e.g. groundwater monitoring wells)
5. Tunnel Facilities Contract (DB contract)
6. Other costs (e.g. Welland River issues)
7. Retirements/Niagara Exchange Agreement costs (i.e. Ontario Power/Toronto Power demolition and construction)

These WBS/CBS elements were then further broken down into Level 3 work packages, Level 4 components and Level 5 activities.

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[28] Midway through the project the Contractor switched from the P3 version of Primavera to P6. This caused some short-term file incompatibility problems for the OR.

Interest and contingency costs were calculated for each of the Level 2 WBS/CBS elements. This would allow for accurate cost allocations to OPG's asset accounts for the overall tunnel facility.

In preparation for the ADBA negotiations, the OR developed a very comprehensive Excel®-based cost model for the tunnel work[29]. This model was used to check the estimates prepared by the Contractor. In most cases the OR and Contractor were able to reconcile their individually prepared estimates, which were fully disclosed to one another. However, for some items such as the estimated quantity of overbreak, cost of diesel fuel, or inflation rates, it was agreed to "baseline" the estimate to establish a reference cost, and then include a mechanism in the ADBA to adjust the final price once the real quantities or costs were known. Through this approach, OPG, the OR and Strabag were able to converge on a mutually acceptable – and ultimately quite accurate – target cost for the ADBA.

4.5.2.2 Cost Control

The OR was responsible for detailed Project cost monitoring, reporting and forecasting. Key features of the cost management process were as follows:

- Excel® was used for all cost collection, analysis and forecasting by the OR[30];
- A budget transfer authorization was used by OPG to manage funds transfers between work packages[31] and to control the use of contingency;
- Project costs were recorded when committed – as opposed to actually spent - wherever appropriate as, for example, when a work package was to be executed via a contract;
- Actual vs. estimated/budgeted costs were tracked at Level 3 – and sometimes Level 4 - of the CBS; and
- Future cost flows and final costs were reforecast monthly. After the ADBA was in place, the OR did a reforecast of the Project final cost, using the detailed estimating model, every quarter.

Under the original DBA fixed price contract the Contractor's actual costs were not available to the OR and OPG. Payments were made monthly based on completion percentages against a cost breakdown included in the contract. Actual progress against these payment milestones was verified by the OR's construction site staff prior to authorizing payment of the invoice. Because the Contractor's real costs were unknown

[29] The ADBA did not change the method by which the above ground, subcontractor work was handled, i.e. the costs of the intake and outlet work remained essentially fixed price per the original subcontract amounts.

[30] OR Project Controls staff believed that this gave much more transparency into cost controls than the use of commercially available project management software packages.

[31] If one work package was forecast to be underspent, surplus funds could be transferred to another work package that was forecast to be over the original budget. This avoided the need to route funds transfers through contingency.

prior to the ADBA, the OR was unable to calculate a Cost Performance Index (CPI) for the Project.

Although it was originally intended to transfer OR cost data automatically into the OPG SAP® system, this idea was abandoned when it was deemed to be too difficult to do so; cost data was therefore transferred manually from the OR to OPG throughout the Project.

ADBA Cost Control

The Amended Design-Build Agreement was an "open book" contract in which all Strabag costs were collected in QuickBooks® and were available electronically for inspection by OPG and the OR. Under the ADBA, costs were categorized as either Allowed or Disallowed. A Disallowed Cost was any cost from a specific list in the ADBA, including such items as costs to vacate liens filed by the Contractor and subcontractors, non-project head office costs, income taxes and withholding taxes. Disallowed Costs also included the cost to repair nonconformances that had been identified by the OR but not reported by the Contractor[32]. In total there were 19 categories of Disallowed Costs. The contract included a formal method for OPG to advise the Contractor that a cost would be disallowed.

Any Contractor planned expenditures for goods or services of more than $100,000 required prior OPG authorization through a formal approval process.

OPG paid all of the Contractor's actual, Allowed Costs on a monthly basis. Contractor draft invoices were first subject to a cost audit by Durward, Jones, Barkwell, a third party auditor retained by OPG, prior to being formally submitted for payment approval. As well as ensuring that the work progress had been accurately reported by the Contractor, the OR would also do certain reasonableness tests on cost items, based on its own records and observations, and check to ensure that no Disallowed Costs were being included in Contractor invoices before recommending payment.

Because both a detailed Contractor estimate and the actual costs of work performed under the ADBA were available after mid-2009, the OR was able to calculate and report a Cost Performance Index[33] (CPI) in addition to the SPI for the latter half of the Project.

4.5.3 Progress Reporting

Throughout the Project, work progress including TBM mining rates, delays, geology, and overbreak was monitored and reported to OPG on a daily basis by the OR construction management staff at the work site. The OR also prepared weekly status updates for

[32] If the Contractor identified and reported a nonconformance, the cost to rectify it was an Allowed Cost.

[33] CPI = Earned Value/Actual Cost. It is a measure of cost efficiency and a CPI ≥ 1 indicates that a project is on track to finish within the approved estimate.

OPG that included a 2-week projection of activities under the ADBA as well as cost and schedule status and current safety, environmental or other issues and concerns for the Project.

In addition to daily and weekly progress and status reports, the OR prepared and submitted a comprehensive monthly Project report that included information concerning:

- Tunnel work progress and schedule status;
- Project costs;
- SPI and CPI;
- Safety;
- Security;
- Environmental performance;
- Permits and approvals status;
- Design progress;
- Project issues and associated actions;
- Claims;
- Stakeholder communication and issues;
- Risk management; and
- Quality (Non-conformance information).

These monthly reports also included information supplied by OPG giving a summary of the status of the Ontario Power GS and Toronto Power GS reversion subprojects until this work was completed in August 2007.

4.5.4 Change Management

A formal change management process was used to ensure that neither the physical characteristics of the facility nor the Project cost, schedule or risk profile would be modified without a thorough review and formal approval of any proposed change. The change and claims management processes were outlined in the contract and a more detailed procedure, with accompanying forms, was documented in the OR's Policies and Procedures Manual for the Project. The change control process involved three steps:

4.5.4.1 Change initiation

A proposal for a Project change could be initiated through either a Contractor-prepared Project Change Notice (PCN) or through a draft Project Change Directive (PCD) prepared by the OR/OPG. These would include:

- A description of the proposed change;
- The reason for the proposed change;

- The impact of the change on aspects of the Project such as form, function, reliability and cost effectiveness;
- The consequences of not making the change;
- Cost impact of the change; and
- Schedule impact of the change.

4.5.4.2 Change Control Board Review

Proposed changes were reviewed by a Change Control Board (CCB) which consisted of the:

- OR Project Manager (Chairperson);
- OPG Project Director;
- OPG Director of Finance[34] ; and
- OR Project Controls Manager.

Other specialists could also be invited as participants upon request of the chairperson. A representative from OPG Law acted as an advisor to the CCB after initiation of the ADBA.

CCB meetings would be convened as necessary. A member of the OR staff would generally present the proposed change to the CCB. After reviewing the proposed change, the CCB would vote either to approve it or to reject it, with reasons. If the proposal was approved the CCB Chairman would prepare a recommendation to the Project Sponsor (Vice President, Hydroelectric Development). The Sponsor could then sign back the recommendation as approved, request a modification, or reject it with reasons and a path forward.

4.5.4.3 Project Change Directive

Approved changes were formalized and transmitted through a Project Change Directive, prepared by the OR Project Controls Manager, that would instruct the Contractor to proceed with the change. The main tunnel contract included the required format for documenting PCDs. As with the PCN or draft PCD, the final PCD would include information concerning:

- The change to the scope of the contract or purchase order, described in sufficient detail as to be "indisputable";
- Adjustment to the Project cost and schedule (Target Cost and Target Schedule in the case of the ADBA); and
- Changes to any other terms or conditions of the contract. Such changes required sign-off by OPG Law Division.

PCDs were approved by OPG at the appropriate level of OAR signing authority.

[34] Prior to the ADBA, the other OPG member was the Project Sponsor.

After implementation of the ADBA, if a PCD did not involve a "material" (i.e. cost of more than $100,000) increase in the work or a change in the target cost or target schedule, it was considered a "deemed amendment" [35] to the ADBA and required only signatures by OPG and the Contractor to be implemented. Any other approved PCDs required the additional step of issuing a formal amendment to the contract before being implemented. Amendments to the ADBA required the signature of the President/CEO (or delegate) of OPG as well as Contractor agreement.

The OR tracked the status of, and maintained logs of, PCNs and PCDs and also maintained a conformed copy of the Design-Build Agreement with approved changes.

4.5.4.4 Claims

Claims from the Contractor would generally arise where the Contractor was seeking cost and/or schedule relief for encountering unexpected conditions for the work. Claims could also be made if the Contractor objected to a Project Change Directive from OPG. The initial notice of a claim had to be submitted within a prescribed time frame after the occurrence leading to the claim. The formal claim was then more formally documented via the PCN process.

An attempt would first be made to negotiate the claim with the Contractor. The Project Manager and other relevant OR staff would review the statement of claim, hold discussions or non-binding negotiations with the Contractor, and prepare a written opinion on the merits and amount of the claim for review. If a resolution was agreed upon, the Project Manager would convene a CCB meeting and, following the CCB procedure described above, would transmit a decision on the claim to the Contractor. Under the ADBA if the Contractor disagreed with the decision, it could issue a Notice of Informal Resolution to have the claim referred to a Steering Committee consisting of one senior representative each of the Contractor and OPG. If unable to reach agreement the Steering Committee could refer the claim to an expert or experts for a recommendation or, failing agreement at that stage, the claim would go to arbitration.

4.6 Risk Management

Risk management for the Project followed relevant governance as well as generally accepted project risk management practices that included:

- Risk management planning;
- Risk identification and assessment (both qualitative and quantitative assessments were done);
- Risk response planning;

[35] A slightly different definition of "deemed amendments" was actually introduced to the original DBA in September 2008 via Amendment 5. Although they could be implemented through a PCD, "deemed" amendments were also often incorporated into the next formal Amendments to the ADBA.

- Risk monitoring and control; and
- Risk reporting.

4.6.1 Risk Management Plan

The OR prepared and issued Revision 0 of the Project Risk Management Plan in October 2006. The OR also prepared subsequent plan revisions (R1 – May 2007, R2 – May 2008, and R3 – August 2008). Revision 4 was prepared by OPG and issued in April 2012. An earlier version of the plan reflected a combination of OPG and HMM approaches to risk management. Revision 4 was prepared in accordance with the corporate governance standard OPG-STD-0062 in effect at the time.

The risk management plans outlined the overall process steps to be followed, responsibilities of the various parties, and the methods and tools - such as the format of risk registers - that would be applied to the process.

4.6.2 Risk Identification and Assessment

During Phase 1 (Planning and Procurement) of the Project, OPG retained URS Canada Inc. to facilitate risk management activities that included risk identification workshops, preparation of initial risk registers, and both qualitative and quantitative risk assessments.

The URS methodology incorporated relevant elements of the recently produced International Tunnelling Insurance Group draft "Code of Practice for Risk Management of Tunnel Works" (the "Code")[36].

4.6.2.1 Qualitative Assessment

Four facilitated qualitative risk workshops, with subject matter experts from OPG, HMM and URS were held during the pre-tender period[37]. To aid in identifying and assessing the risks during these workshops, the URS risk assessment process grouped the risks into eight “hazard”[38] categories. Each workshop focused on a subset of the eight categories.

The risk assessment process used in the workshops included the following steps:

- Each hazard was assigned a probability between 1 (very low) and 5 (very high) by the expert panel. The OPG operational risk assessment criteria in effect at the time were used to numerically rate the impact – also on a 1 to 5 scale - of each

[36] Section 6.4.2 of the Code states that “A Risk Assessment shall be carried out and a Risk Register shall be prepared for the preferred project option (or options). This Risk Register should include the perceived hazards and associated risks for the preferred project option (or options) and indicate potential mitigating measures with comprehensive explanations for their basis, based on the studies carried out during the Project Development Stage. This Risk Register shall be included within the information provided to tenderers during the Construction Contract Procurement Stage.”

[37] Workshops were held on December 9 and December 23, 2004, and January 14 and February 4, 2005.

[38] Under the URS methodology a “hazard” is a situation that, if it occurs, brings about a negative impact on achieving project objectives. Other methodologies may refer to this as a “risk event”.

hazard on the following Corporate and Project objectives: financial, schedule, corporate reputation, regulatory/legal, health and safety, and environmental.

- Using the product of the probability rating and the highest impact rating, an overall risk level was then calculated for each hazard using a standard 5 X 5 risk heat map. The heat map was used to categorize hazards as being of "low", "medium" or "high" risk. It should be noted that any hazard that had an impact level of 5 on *any* of the objectives, regardless of probability, was categorized as a "high" risk to reflect the importance of low probability but high consequence events.

The above steps were done for both the *inherent* risk and the *residual* risk. The inherent risk assessment assumed that no particular control measures for the hazard were in place, while the residual risk assessment was based on control measures that had already been taken at the time of the workshop. The following table shows the number of hazards identified in each category as well as the number that were assessed as being of "high" risk.

Table 4.2

Hazard Category	Total Hazards Identified	High Risk – Before Mitigation Measures	High Risk – After Mitigation Measures
Approvals and permitting	11	6	5
Stakeholder issues	2	1	0
Planning and conceptual design	9	3	2
Financial and contractual	17	5	5
Logistics and access	5	1	1
Final design and construction	17	8	6
Environmental issues	11	0	0
Safety and security	14	5	1
Total	86	29	20

Of all the hazards, only eleven that evaluated as "high" risks, before mitigation were considered to have a probability rating of 4 or 5 (i.e. likely or probable.) Sixteen hazards with low probabilities were still considered "high" risks due to having an evaluated impact of 5 on one or more of the corporate objectives.

Results of the URS qualitative analysis were documented in the "Niagara Tunnel Project Qualitative Risk Assessment Report", dated February 24, 2005.

As part of their proposals the tunnel proponents were required to prepare their own independent risk assessments and were required to submit the results of these assessments as summary risk registers, which were considered by OPG during proposal evaluation.

4.6.2.2 Quantitative Assessment

At two of the URS workshops, the expert panel members were also asked to further quantify the consequences of selected hazards[39] in terms of the possible range of cost and schedule delay impacts. The impact ranges were given as 3-point (low, mean and high) estimates that were input as parameters into probability functions to be used in a Monte Carlo analysis of the Project cost and schedule. The Monte Carlo analysis then produced probability distributions of Project cost and duration that could be used to establish recommended contingency amounts that would reflect a particular level of confidence in the estimate and the scheduled completion date.

Based on the URS analysis, the initial cost and schedule probability distributions suggested the following contingencies:

Table 4.3

	Cost Contingency	Schedule Contingency
For 80% probability of non-exceedance	$20 million	23 weeks
For 90% probability of non-exceedance	$33 million	30 weeks

The results of the quantitative assessment were documented in a second URS report, “Niagara Tunnel Project – Quantitative Risk Assessment Report” – May 2005.

The initial risk analysis was conducted before responses to the RFP were received from the design-build proponents. Because of this, the analysis considered only “generic” risks without taking into account possible differences in design, construction methods, commercial terms or other aspects of the proponents’ proposals that could lead to variations in the types and consequences of hazards. Therefore, it was recognized at the time this analysis was done that further assessment of the risks, and the necessary contingencies, would have to be carried out once the proposals were received and evaluated.

After the design-build proposals were received and analyzed in May-June 2005, OPG updated the quantitative analysis model that had been developed by URS, with the intent of:

- Confirming the overall assumptions;
- Confirming estimated numerical inputs;

[39] Not every hazard was included. URS used a number of criteria to select which hazards would be included in the quantitative analysis, e.g.: “the risk factor (*hazard*) should not be associated with a condition or event whose chance of occurrence is remote”

- Identifying additional hazards and removing hazards that were no longer relevant; and
- Adapting the assessment to reflect differences among the proposals.

Expert panel workshops were held on June 29 and July 12, 2005 to identify necessary updates to the assessment. Participants in these workshops were mostly the same individuals who had contributed to the earlier assessment facilitated by URS and represented engineering, legal, commercial and other areas of expertise.

Overall assumptions and estimates that were used for the re-assessment included:

- For all hazards, only direct cost impacts (e.g. incremental materials and labour to correct a problem) were considered. Costs of the Contractor's and OPG's "burn rate[40]" during delays were excluded;
- Schedule delays were estimated in terms only of critical path impact; and
- The consequences of schedule delays were transformed into equivalent costs by multiplying delays by a "burn rate" of $275,000 per day, based on:

Contractor's labour	$225,000
Stand-by cost of equipment	$ 25,000
OR cost	$ 20,000
OPG cost	$ 5,000
	$275,000

Using the quantitative risk register from the URS report as a reference, all hazards were reviewed and their probabilities of occurrence, as well as cost and schedule consequences, were re-evaluated for each proposal. Some of the hazards were no longer relevant and were removed from the register. Five new hazards were added to the register based on information in the Design-Build proposals (e.g. more detail on geotechnical risks). Differences among the three proposals were also reviewed, which led to different numerical estimates for certain hazards as applied to each proposal. For example, the risk of water inflows into the tunnel depended on the tunnel alignment, type of tunnel boring machine, and the liner design, which varied among the proposals.

In the updated analysis, the top two contributors to potential cost increases were found to be: 1) "Dispute Review Board Interpretation of Agreement unfavourable" and 2) "DSC [Differing Subsurface Conditions] claim due to rock strength." These same two factors, in reverse order, were also identified as the top two contributors to potential schedule delays for which OPG, rather than the Contractor, would be responsible.

[40] Burn rate is essentially the fixed cost of maintaining staff, facilities and equipment in place on the project during a given time period.

Based on the updated quantitative assessment for the selected Design-Build proposal, OPG's cost contingency for the tunnel contract was revised upward to $96 million to meet a 90% confidence level. The schedule contingency was set at 36 weeks, based on the estimated OPG-accountable delay[41], also at 90% confidence. The total Project contingency at release ($112 million) included the $96 million for the tunnel contract, as well as additional contingencies for other Project elements.

4.6.3 Risk Registers

The risks identified during the URS-led analysis, and later updated by OPG, were documented in an "OPG Risk Register", created in Excel®, which included risk description and consequence information, probability and impact ratings, and mitigation plans.

As a condition of providing Builder's All Risk insurance coverage for the Project, the underwriters required that significant portions of the International Tunnelling Insurance Group "Code of Practice for Risk Management of Tunnel Works" be adopted. As a result, OPG and the Contractor were required to share details of their respective risk assessments and to systematically coordinate construction phase risk management efforts. A second risk register, known as the "Construction Risk Register" was created to capture those OPG and Contractor-identified risks that were not deemed to be commercially sensitive or confidential by the respective parties; in general these risks were related to the technical aspects of project execution. This risk register also showed which entity (OPG or the Contractor) was the risk "owner", responsible for management of the risk.

For OPG's internal management reporting purposes a third risk list – the "Top Ten" list - was created to summarize information regarding the most critical risks from the OPG Risk Register and the Construction Risk Register. Neither the OPG Risk Register nor the Top Ten list was shared with the Contractor.

Following the formation of the Amended Design-Build Agreement in 2009, the OPG Risk Register was modified, by combining some of the individual hazards from the original registers into broader risk event categories[42], and also by including some of the risks from the Construction Risk Register, to become the "NTP Key Risk Register". This risk register no longer showed the inherent (before mitigation) risk qualitative data, but only included the residual (after mitigation) risk data. Risk champions or owners were assigned to each risk. A subset of the Key Risk Register data was also created as the "Key Risk Register Summary."

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[41] Only delays for which OPG would be accountable were considered since the contract included liquidated damages for contractor-caused delays.

[42] Through the combination process, some of the originally identified *hazards* became *risk causes* for the higher-level risk events in the new register.

OPG also developed, and periodically reviewed a risk register, showing risks associated with the relationship with the Owner's Representative. The most serious risks identified were associated with continuity of OR key Project personnel, in particular the Project Manager. During the early portion of the ADBA, there was also an initial concern regarding the adequacy of OR processes for overseeing Contractor progress and payments under the new agreement.

4.6.4 Risk Allocation

As part of risk management planning it was recognized that specific risks should be assigned to the organization (OPG or the Contractor) that could best manage that risk. The Construction Risk Register identified which of the two parties would "own" each risk and therefore take responsibility for control or mitigation measures.

OPG originally assumed part of the risk of Differing Subsurface Conditions, through the incorporation of the agreed Geotechnical Baseline Report C in the contract documentation. A contingency amount was included in the approved Project budget to cover possible costs associated with this risk. The ADBA more fully defined the way the DSC risk events such as excessive overbreak would be measured and the cost differences that would be allocated to each one.

In general, with the exception of the risk of property acquisition delays, which was OPG's, most other risks associated with the design and construction of the work, were allocated to the Contractor. The Contractor was also allocated the risk of schedule delays related to obtaining permits and approvals.

4.6.5 Risk Monitoring

The Construction Risk Register was reviewed and updated approximately every six weeks throughout the entire Project. The OPG Risk Register was initially internally reviewed with the OR every quarter. Following the conversion to the Key Risk Register in 2009 the risk review frequency became monthly, with the various designated "risk champions" reviewing their assigned risks on a rotational basis (i.e. not all risks were reviewed every month).

The purpose of the risk reviews was to update the risk registers to reflect the progress of the work, including mitigation activities, and to capture any changes in the risk profile, including new risks or risks that may have arisen because of mitigation measures and changes in the work processes or as-found conditions.

4.6.6 Insurance Coverage

As part of the design and construction risk transfer strategy, OPG obtained insurance coverage for Wrap-Up Liability, Builders' All Risk and Marine Cargo Coverage. The OR maintained Errors and Omissions Insurance. The Contractor provided Errors and Omissions Insurance, Motor Vehicle Liability Insurance, Construction Equipment Insurance, and Workers Compensation coverage.

To mitigate the financial risk to OPG, the DBA required Strabag to provide a letter of credit for $70 million as well as parental indemnities guaranteeing its performance and indemnifying OPG for any damages resulting from a breach by Strabag. Strabag also was required to provide a maintenance bond of 10% of the contract price to remain in force until the end of the warranty period, which was one year following the date of Substantial Completion. OPG and Strabag subsequently agreed to maintain the letter of credit for the duration of the warranty period in lieu of the maintenance bond.

As a condition of the Builders All Risk insurance agreement, OPG was required to periodically provide Project risk information and updates to the insurers.

4.6.7 Additional Risk Assessment for ADBA

As outlined in section 3.5.3, a risk assessment was conducted in 2009 by OPG Risk Services to support the revised estimate and schedule for the Amended Design-Build Agreement and the Superseding Business Case. Two additional risk assessments were conducted later as described below.

In May 2010, a quantitative (Monte Carlo) analysis was carried out by OPG Project Risk Management (PRM) to ascertain whether the then-current schedule for the intake end cofferdam removal and outlet end dewatering structure and rock plug removal was still feasible. The analysis concluded that the dates were still valid.

A second detailed quantitative review of the Project risks was conducted in March-April 2011 to re-examine the probabilities of achieving the target schedule and cost outcomes. This analysis included two workshops facilitated by PRM. The first workshop dealt with schedule uncertainty. The OPG/OR Project Team and the Contractor's Subject Matter Experts developed three-point (pessimistic, most likely, and optimistic) estimates for each of the major remaining scheduled activities. These estimates were input into Pertmaster®, a software package used to run a Monte Carlo simulation of the schedule to establish a completion date probability function curve.

The second risk workshop was held to review the adequacy of the cost contingency. The OPG/OR NTP Project Team worked with PRM to identify the remaining probability of occurrence and three-point schedule and cost impact estimates for fifteen of the significant Project risks[43] from the Key Risk Plan summary. Schedule impacts were converted to costs using "burn rates" calculated by the Project Team and OPG Finance.

From the analysis, it was concluded at the time that:

[43] Some of the key risks from the original risk plan were excluded because of the current state of progress of the project (e.g. tunnel mining was almost complete at the time).

- There was very high confidence that the tunnel would be in-service by July 31, 2013, well in advance of the December 2013 target date approved by the Board in the Superseding BCS;
- There was low confidence that the tunnel would be in-service by the ADBA Target Schedule date of June 15, 2013 (subject to adjustment due to excess overbreak);
- There was very high confidence that the final Project cost would be below the Superseding BCS approved estimate of $1,600 million; and
- There was medium confidence that no more than half of the $164.4 million Project contingency would be required.

As outlined in Section 5.3 (Schedule Outcomes) Strabag was able to advance the in-service date, to well before the Target Date, by changing the approach to removal of the tunnel lining equipment to allow earlier watering-up and cofferdam removal at the intake end.

4.7 Health and Safety Management

For most of the Project, the DBA/ADBA established the Contractor as the “Constructor” under the OHSA Construction Regulations. This relieved OPG in its “Owner Only” role of the responsibility – and risk – for health and safety management of the Contractor’s work force.

The Contractor was required to submit a Project Specific Site Safety, Security, Public Safety and Emergency Response Plan (SSSP), both as a draft with the proposal and as a submission after contract award, outlining how they would fulfill their obligations as Constructor to manage Project health and safety. The SSSP submitted by Strabag was actually prepared by its major civil subcontractor, Dufferin Construction. OPG and the OR reviewed the SSSP for acceptability.

The Contractor was required to report all safety related incidents to the OR who would in turn notify the OPG Project Director. The Contractor was responsible for investigating, reporting, and implementing remedial actions.

The OR was tasked with overseeing the Contractor’s compliance to the SSSP, as well as relevant regulations, through observations and periodic audits. The OR Health and Safety Advisor made site visits on a weekly basis. These visits typically reviewed:

- Use of established safety procedures within the SSSP;
- Development and use of Job Safety Analyses (JSAs)/pre-job briefings/JSIs;
- Inspection program;
- Incident management; and
- Housekeeping/Workplace Hazardous Materials Information System (WHMIS) program.

Any OR observations of hazards or noncompliance were communicated to the Contractor at regular weekly meetings. For more serious issues, a Project Safety Compliance Observation Form was given to the Contractor with a request for a response although, in an Owner Only role, OPG and the OR could not directly instruct the Contractor to take any specific measures regarding the safety of its workers.

OPG was required to operate control gates at the INCW for ice, flow and water level management, which would affect in-water work at the intake end and possibly constrain the Contractor's construction activities requiring access to and along the INCW structure. Without full control over this work area the Contractor could not, under the Construction Regulations, be the "Constructor" during some periods of the Project. Therefore, early in the Project, OPG applied for and received approval from the Ministry of Labour to designate a discrete portion of the Project around the INCW as the separate "INCW Part Project" for which OPG would be the Constructor during two stages[44] of the intake end work. For the Part Project the OR acted on OPG's behalf to manage on-site safety supervision. This included:

- Conducting its own independent pre-job hazard assessment of the Part Project for use as a reference when reviewing the Contractor's hazard assessments;
- Reviewing the Contractor's Site Specific Safety Plan and JSAs;
- Ensuring that necessary safety training was delivered either by the Contractor or by OPG personnel;
- Monitoring safety performance through regular inspections;
- Ensuring the Contractor met requirements for incident reporting, investigation and follow up;
- Managing the Project safety audit program, and monitoring corrective actions;
- Attending the Contractor's toolbox and pre-job briefing meetings;
- Participating in the Joint Health and Safety Committee; and
- Holding work protection for the Contractor.

For the Part Project the Contractor was required to meet OPG's health and safety policies and requirements and, as Constructor, OPG through the OR could provide direction to the Contractor in health and safety matters.

OPG provided the necessary work protection training for OR and Contractor staff.

[44] Designation of a "part project" is allowed under the regulations. The Part Project was in effect at the intake end during Stage 1 (construction of the cofferdam and in-river replacement of the ice accelerating wall) and Stage 3 (removal of the cofferdam). For Stage 2 when work was being carried out within the cofferdam, the Contractor was the Constructor since OPG's operations would not affect worker safety in this area.

4.8 Environmental Management

As the Owner of the NTP, Ontario Power Generation was ultimately accountable for complying with the conditions of the Environmental Approval and for obtaining the necessary environmental permits and approvals from government and municipal agencies. Some required approvals had already been received during the earlier (1990s) attempt to start the Project[45]. Starting in the Planning and Procurement Phase, the OR was tasked with initiating some permit applications in order to ensure they would be available when required for the start of construction. However, through the DBA/ADBA, the Contractor was assigned responsibility for completing or obtaining many of the remaining necessary permits and approvals directly related to construction activities. Approval applications and associated documentation were provided to the OR and OPG for review prior to submission to the appropriate agency.

Some of the main environmental concerns that had to be addressed, either because of EA conditions or to meet regulatory requirements, included:

- Management and disposal/storage of excavated materials (e.g. through their use in brick manufacturing or as aggregate);
- Management of contaminants from excavated shale materials containing naturally-occurring BTEX (Benzene, Toluene, Ethyl benzene and Xylene);
- Emissions to air, including equipment and vehicle emissions as well as dust from the transport of material removed from the tunnel, from vehicle movement, or from blasting;
- Emissions to water, including run-off, silt or sediment from construction activities as well as potential spills of fuel, lubricants or hydraulic fluid from construction equipment;
- Management of hazardous and non-hazardous waste;
- Noise from construction activities;
- Impacts of blasting on fish as well as structures in the vicinity of the Project;
- Impacts on groundwater along the tunnel route;
- Impacts on local vegetation and wildlife (e.g. bird nesting);
- Impacts on local residents, tourist attractions and businesses; and
- Impacts on local roads and transportation.

Minimum requirements for the management of some of these issues were included in the contract as part of the Owner's Mandatory Requirements and in other sections of the contract. The Contractor was required to develop a comprehensive Environmental Management Plan[46] that addressed permitting and approval processes as well as

[45] For example, an exemption from the Navigable Waters Protection Act, DFO authorization of "destruction of fish by means other than fishing".

[46] The Strabag Environmental Management Plan was prepared by its subcontractor Morrison Hershfield. A draft plan was submitted with the original proposal and a final plan was submitted after contract award.

providing more detailed plans for the management of environmental concerns. The Contractor also prepared an Environmental Compliance Plan that described how tools such as environmental audits, risk management analysis, quality assurance/quality control, inspection, monitoring and training would be used to ensure compliance with the contract and legal and regulatory requirements.

The role of the OR was to assist OPG by developing the necessary documentation for applications for permits and approvals as well as to provide oversight and periodic audit of the Contractor's environmental management and reporting.

4.9 Quality Management

4.9.1 General

Although no overall Quality Plan was produced for the Project, the required elements of project quality assurance and quality control were embedded in a number of Project documents. The original Design-Build and Amended Design-Build Agreements incorporated the Contractor's ISO 9001 compliant Quality Manual and Quality Plans and Procedures. The overall intent was that this QA system, audited for compliance by the OR, would form the basis for tunnel Project quality management.

The OR did a number of formal quality audits of Strabag and its subcontractors. In addition, one Project level audit done by OPG Internal Audit after implementation of the ADBA examined OPG's QA oversight.

OR oversight of the Contractor's quality assurance and quality control process was described in the Project Execution Plan sections and supporting Project procedures for:

- Engineering Management;
- Construction Oversight, Installation and Commissioning;
- Project Controls and Reporting (change management sections); and
- Records Management.

The OR procedures were supported and documented by the use of numerous forms to capture records of the observations of the Contractor's work and communications between the OR, the Contractor and OPG.

The OR held periodic (several times per year) meetings with the Contractor to review QA/QC issues and actions. OPG also received quality updates from the OR during the regular weekly meetings.

4.9.2 Supplier Quality Assurance

In addition to Strabag, a number of subcontractors also maintained ISO 9001 compliant Quality Assurance programs throughout the Project. Some of these subcontractors were:

- ILF Beratende Ingenieure ZT Gesellschaft mbH (design subcontractor);

- Dufferin Construction Inc.;
- Bermingham Construction Ltd.;
- McNally Construction Inc.;
- Allied Fabricators Inc.; and
- Geo Foundations Contractors Inc.

The Contractor was responsible for conducting factory testing on various equipment and components of the work such as the TBM and associated backup equipment, and the intake and outlet gates. The OR and OPG were notified in advance of factory testing to allow for verification which was a condition for payment certification.

4.9.3 Design Quality

The Contractor prepared a comprehensive Design Quality Plan that was divided into a preparative phase, a preliminary design phase, and a detailed design phase. The plan covered all aspects of the design such as the cofferdam, intake and outlet civil works and structures, the diversion tunnel, mechanical and electrical works, dewatering system. For each item it listed the design activities, quality requirements and quality controls as well as responsibilities for QA verification.

Required Contractor engineering submittals to the OR and OPG included:

- Design basis documents;
- Detailed construction drawings;
- Detailed construction and material specifications;
- Checked engineering analysis and design calculations;
- Minutes from the Contractor’s design review meetings;
- Construction methods;
- Environmental protection procedures;
- Quality assurance/quality control plans and procedures;
- Specific method statements;
- As built construction drawings and specifications; and
- Checked design calculations for revisions to the 100% construction documents.

Appropriately qualified OR professional engineering staff reviewed the Contractor submittals to verify that they were in general conformance with applicable laws, the Owner’s Mandatory Requirements, the terms of the DBA/ADBA, the Contractor’s design basis documents, and other related submittals. In some cases, OPG engineering staff would also review and comment on Contractor submittals. Submittals could be accepted, or returned for revision with or without a requirement for resubmittal. Acceptance of a submittal by the OR did not constitute “approval” and did not relieve the Contractor of its contractual obligations regarding design, fabrication, construction, suitability for purpose, or warranties under the DBA/ADBA.

4.9.4 Construction Quality

The Contractor developed, and submitted for OR review, individual method statements and quality plans describing the activities, quality requirements, and the QA/QC responsibilities for each major aspect of the tunnel such as tunnel excavation and support, shotcreting, waterproofing system, concrete work and grouting.

The OR closely monitored Contractor activities during all construction shifts. OR construction monitors used detailed forms and checklists to record progress and audit operations and final product quality against the designs and methods. Contractor activities dealing with permanent works were checked before “covering” (e.g., prior to concrete installation, backfilling, etc.) to confirm that the Contractor had performed the necessary quality control to ensure compliance. TBM tunneling and final concrete liner monitoring was done on a full-time basis during every shift. Some activities such as profile restoration were monitored on a part-time basis by OR staff who looked after a number of concurrent tunnel operations. One critical item monitored was crown overbreak, which was measured on a frequent basis because the ADBA allowed for adjustment of the contract schedule and target cost per the Major Risk Table in the event that actual overbreak values exceeded the baseline overbreak amount.

4.9.5 Nonconformances

If work was found not to conform to the contract specifications or the Contractor’s Quality Assurance/Quality Control Plan, a Non-Conformance Notice (NCN) could be issued by either the Contractor or the OR. If the nonconformance was found by the OR rather than the Contractor a Disallowance Advisory could be prepared, as outlined in the ADBA, advising the Contractor that future non-conformance would result in a Disallowed Cost. NCNs were logged by the OR and tracked through a Nonconformance Register until their disposition was complete.

Appendix B is a flowchart showing the nonconformance management process.

4.10 Communication

4.10.1 Stakeholder Engagement and Communications

The location, scale and duration of the Niagara Tunnel Project meant that there would be significant impacts on the local community, including tourism, transportation, other municipal services such as water or sewer and employment. It was recognized from the outset that maintaining good relationships with the community would be critical, not only for the success of the NTP, but also to ensure that the existing community support for the Niagara Plant Group and the positive public perception of OPG were not compromised.

In addition to Federal and Provincial regulatory agencies, some of the key external stakeholders for the NTP included:

- Niagara Parks Commission;
- Niagara Escarpment Commission;
- Niagara Peninsula Conservation Authority;
- Regional Municipality of Niagara;
- City of Niagara Falls;
- Town of Niagara-on-the-Lake;
- Niagara Falls Tourism; and
- Local suppliers, contractors, building trades.

In 1993, Ontario Hydro, as part of its commitments under the EA submission, had negotiated a Community Impact Agreement (CIA) with the local municipalities to mitigate the predicted impacts of the construction of the originally intended Niagara River Hydroelectric Development (NRHD) on tourism, roads, water supply, and sewage treatment. Under the CIA the municipalities agreed to grant all necessary local construction permits for the Project. In exchange, Ontario Hydro was required to:

- Consider local planning requirements in developing the NRHD;
- Consult with the municipalities on an ongoing basis;
- Address complaints from residents impacted by the Project;
- Fund improvements and maintenance for roads impacted by construction traffic;
- Provide funds to mitigate impacts on sewage treatment facilities;
- Procure emergency services from the municipalities where practical and cost effective; and
- Seek opportunities to enhance local economic benefits including provisions for engagement of local contractors, suppliers and labour.

In August 2005, the CIA was amended to reflect the fact that the NRHD would be constructed in phases, the first of which would be the Niagara Tunnel Project. Payments of $7.87 million were made by OPG under the amended agreement in October 2005 after the Project received final approval.

A Community Liaison Committee was established to facilitate communication between OPG and local community officials. The Committee had representatives from the Regional Municipality of Niagara, City of Niagara Falls and Town of Niagara-On-The-Lake, as well as the Project Director, OR Project Manager and the Contractor. Liaison Committee meetings were held three or four times per year throughout the Project.

OPG took measures to ensure timely and accurate notification to the community of important Project events such as approvals, the start of construction, key Project milestones, and Project completion. Public forums such as Open Houses were held as required. Processes were also put in place to communicate with local key stakeholders, interest groups, and the media to ensure that they were fully informed about the Project and could have any questions answered quickly. Community notifications included:

- Media releases and suggested information articles for community newspapers;
- Newsletters to key stakeholders and communities adjacent to construction activities; and
- A public website (www.niagarafrontier.com/tunnel.html) with frequently updated Project information.

Telephone and e-mail hotlines were set up for public complaints. These provided immediate acknowledgement of complaints and were monitored regularly to allow communication of a full response within pre-defined time limits. A protocol was established to direct all inquiries (and complaints) to appropriate NPG staff who would notify the OR for investigation and resolution of the issue with the Contractor. The Contractor was also required to inform the local construction industry of potential Project related employment and supplier opportunities, in line with the provisions of the CIA.

The OR or the Contractor would notify OPG Media Relations when fire, ambulance or police services were called to the Project site.

4.10.2 Internal Communications

An important objective of the Project was to "ensure sufficiently detailed reporting to the OPG Board of Directors and the Province of Ontario such that their confidence in OPG's ability to execute large projects was maintained."

The Project team communicated information to OPG senior management and the Board through the following mechanisms:

Table 4.4

Stakeholder	Information	Frequency	Media	Responsible
Phase 1- Planning and Procurement				
Board	• High level performance metrics • Key external issues	Quarterly	Meeting and Presentation Meeting Handout Board Memo	Major Projects Committee/ Project Sponsor
Major Projects Committee	• High level performance metrics • Key external	Weekly (Memo) Quarterly	Memo Memo/Verbal/Presentation	Project Sponsor/ Project Director

	issues			
Phase 2 - Execution				
OPG Board/Risk Oversight Committee (ROC)	• Written / verbal update at each Board/ROC meeting • Written Major Projects Status Report including cost and schedule metrics	Quarterly Quarterly	Verbal Status Report Written Report	SVP Hydro-Thermal Operations SVP Hydro-Thermal Operations
OPG Enterprise Leadership Team	• Written report and verbal update • Written update at the OPG Key Results meeting • Monthly Report – Executive Summary distributed to ELT	Weekly Monthly Monthly	Verbal Status Report Written Report Written Report	SVP Hydro-Thermal Operations Project Sponsor
SVP Hydro-Thermal Operations	• Cost, schedule, safety, environmental, key risks and quality reports • Issues/concerns and actions	Weekly	Verbal Status Report	Project Sponsor

The OPG Board remained actively involved in the Project throughout its duration, primarily through the activities of its Major Projects Committee (MPC), now called the Risk Oversight Committee (ROC).

The MPC:

- Reviewed and approved the proponent pre-qualification and RFP processes;
- Participated in the meetings used to determine which of the pre-qualified proponents would be invited to submit proposals;
- Provided oversight of the contract negotiations, and reviewed and accepted management's selection of the preferred Contractor, Strabag;
- Reviewed the financial analysis underlying the business case for the Project and endorsed management's recommendation, that the Project be approved, to the full OPG Board;
- Was actively involved in the review of OPG's position before the DRB during the DSC contract dispute with Strabag;

- Reviewed the available alternatives with management and endorsed the approach of negotiating a revised contract with Strabag; and
- Recommended the Amended Design-Build Agreement to the full OPG Board for approval along with the Superseding Business Case supporting the new Project budget and schedule.

During the DSC dispute with Strabag OPG established a Contract Litigation Oversight Committee (CLOC) chaired by OPG's Chief Financial Officer to provide independent oversight of OPG's strategy for the dispute resolution and negotiations and to advise OPG senior management on the conduct of the dispute. The CLOC included external members Norman Inkster, former head of the RCMP, and Barry Leon, a lawyer who specialized in international litigation and arbitration. The CLOC continued to advise OPG during the ADBA negotiations with Strabag until an agreement was reached.

5 Project Outcomes

5.1 Safety

Key worker safety performance results were as follows:

Table 5.1

	2005	2006	2007	2008	2009	2010	2011	2012	2013
Hours Worked (x1000)	28	545.8	699.1	712.9	900.1	1224.1	1290.8	1189.6	201.8
Lost Time Injuries	-	4	3	2	1	1	6	15	0
High MRPH Events	1	2	0	0	0	-	-	-	0
Contractor "Serious" Events	-	5	7	11	16	16*	21**	12	-
Contractor "Major" Events	-	1	-	-	3	2	2	2	-
MOL orders	-	50	55	7	20	24	17	33	1

- * 4 of the "serious" events reported in 2010 relate to one incident where a compressor caught fire and 4 workers were exposed to smoke fighting the fire.
- ** 5 of the "serious" events reported in 2011 relate to a single situation where 5 workers experienced similar eye irritation from an unknown cause while installing rock bolts as part of the fall of ground repair.

Between 2005 and September 2013, 6.79 million construction hours were worked on site and 466 safety-related incidents/accidents were recorded. A total of 735 days were lost due to work-related injuries or illnesses. The overall reported LTI frequency (lost time injuries per 200,000 hours worked) was 0.94. This was less than the construction industry average in Ontario that ranged between 1.58 in 2005 and 1.2 in 2009[47].

The Contractor used its own incident categorization scheme and from the Health and Safety Incident Summary log it was not clear that the categorizations were consistently applied or directly comparable to the OPG incident categorizations. However, after implementation of the ADBA, the categorizations were clarified and from 2010 onward Contractor "Major" incidents can be considered roughly equivalent to the OPG "High MRPH" incident classification. There were a total of 13 reported work-related High MRPH or Contractor Major incidents, of which only one resulted in a lost time injury. Two Contractor Major incidents, one in September 2009 and the other in July 2011, were due to fall of ground collapses of part of the tunnel arch prior to installation of the final liner. There were no worker injuries directly related to these events.

There were a total of 207 Ministry of Labour Orders to Comply written over the course of the Project, of which 29 were for the INCW Part Project where OPG was the Constructor. During the period from 2007 through 2011 (for which MOL statistics are available) orders written for the NTP represented 25% of the total orders for *all* tunneling projects in Ontario.

OPG Internal Audit conducted a Health and Safety Audit of the INCW Part Project, where OPG was the Constructor, in September 2006 and found that the OPG/OR safety management processes were effective in managing the risks for that portion of the work. Two high MRPH incidents occurred in 2006 for the Part Project. Both involved in-water work by a subcontractor and neither resulted in a worker injury.

Since the Contractor was the Constructor for all but the Part Project, the OR had limited ability to influence the Contractor's safety management practices. The mechanisms available included the weekly joint inspections, safety discussions at Project meetings, and mini safety audits conducted by the OR. Overall, safety management performance was acceptable.

The Project was successful in avoiding any injuries to members of the public. The only incident that had a potential for risk to non-Project personnel was the inadvertent release in the spring of 2006 of some crib timbers from the demolition of the original accelerating wall. These were transported downstream as far as the Maid of the Mist pool, and could have posed a danger to small craft. As soon as this was known, containment measures were put in place by the Contractor to prevent a recurrence.

[47] Ontario Ministry of Labour Occupational Health and Safety Branch "Construction Sector Plan 2012-2013", June 2012.

5.2 Environment

The Contractor's environmental management performance was judged by OPG to be relatively weak, particularly during the first years of the Project. An environmental audit conducted by OPG Internal Audit in mid 2007 cited a number of concerns including:

- A large number of spills and regulatory infractions;
- Inadequate follow up with corrective and preventive actions, leading to repeat occurrences;
- Failure of the Contractor to adhere to its own Environmental Management Plan, and to keep the plan up to date;
- Failure of the Contractor to report environmental incidents in a timely manner;
- Inexperienced environmental management staff in the Contractor's organization (environmental management was initially provided by Morrison Hershfield, but later taken over directly by Strabag); and
- A need for the OR to improve its reporting on compliance monitoring activities.

Environmental events and regulatory infractions included:

- Many spills of hydraulic oil and other fluids;
- Inadequate treatment of drainage water from the tunneling activities, leading to releases of high levels of sediment into the PGS canal;
- Inadequate dust control measures, leading to complaints from local stakeholders; and
- Water treatment plant exceedances due to excess chlorine and chloride ion concentrations.

By late 2007 the Ministry of Environment was expressing serious concerns with the Contractor's environmental management practices and was apparently even considering prosecution for ongoing non-compliance, although this did not occur. However, the MOE did significantly increase its on-site inspection activities, requiring OPG to provide funding to support the additional MOE costs for this.

The capability of OPG and the OR to have the Contractor make environmental stewardship beyond basic compliance a high priority was limited due to the Owner-only nature of the contract, which generally precluded giving specific direction to the Contractor. However, it appeared that the Contractor's regulatory compliance improved somewhat following the OPG audit and MOE intervention of late 2007.

5.2.1 Reportable Spills

The following table shows the number of spills reported by the Contractor during the Project:

Table 5.2

	Spill Category				
Year	**A**	**B**	**C**	**D**	**Total**
2006	0	5	9	3	17
2007	0	3	2		5
2008	0	0	3	1	4
2009	0		10		10
2010	0		6		6
2011	0		10		10
2012 (Note 1)					4
2013 (Note 1)					5
TOTAL		8	40	4	61

Note 1: Project spills database does not show spill categories for 2012 and 2013. However from the spill report descriptions it appears that they would be Category "C".

Of the total events reported, approximately 37% were due to spills or leaks of hydraulic fluid from construction equipment, 25% were due to discharges of suspended solids in the tunnel drainage effluent, and the remainder involved spills of fuels, shotcrete accelerant, or other miscellaneous fluids. With the exception of one sewage leakage incident (caused by a subcontractor cutting through a force main) in 2006, the remaining "B" category events all involved discharges of water with high levels of total suspended solids.

5.2.2 Regulatory Infractions

Regulatory infractions were, for the most part, incidents of noncompliance with a condition of one of the Certificates of Approval:

Table 5.3

	2006	2007	2008	2009	2010	2011	2012	2013	Total
No. Of Infractions	58	62	7	9	4	4	1	1	146

Of the total infractions reported, approximately 26% were due to water discharges exceeding the limits for Total Suspended Solids. An MOE Provincial Order was issued in December 2006 related to one of these events as well as for contravention of the CofA for Industrial Sewage Works. 22 % of the other infractions were related to BTEX (mostly toluene) exceedances, and 20% were due to oil and grease discharges during one period in March and April of 2007. Other infractions related to excess total residual chlorine and excess chloride ion concentrations in the water treatment plant effluent.

Early in the tunnel mining process NPG staff reported to the OR that they were observing significant dust from the area where material being removed from the tunnel via the conveyor system was being dropped. There were complaints from the Niagara

Parks Commission as early as October 2006 that dust from the conveyor drop site was been carried off site to the adjacent Butterfly Conservatory and Botanical Gardens. Strabag initially attempted to address the problem by installing a sprinkler system at the conveyor transfer points and also installed dust-monitoring instrumentation at the affected sites. The dust problem persisted and eventually led to an MOE Provincial Order being issued on September 20, 2007 that required Strabag to take "all reasonable steps" to control dust emissions, to observe wind speeds, warn of possible off-site dust events, and maintain a log of events. Strabag installed a dust containment structure around the conveyor drop area, and took other measures to monitor and report on dust emissions. The containment structure reduced fugitive dust to an acceptable level.

In January 2009 the Niagara Parks Commission advised OPG that it was claiming damages for past and future impacts of the dust emissions on its property. OPG and the Contractor settled the claim with NPC in August 2011 for actual costs.

5.3 Schedule

As described earlier, the Project milestone dates planned in 2005 were significantly modified in 2009 as part of the Amended Design-Build Agreement. The following table summarizes the key planned, modified and actual Project dates.

Table 5.4

Major Activity	Original Target Date	Target Date (ADBA)	Revised Target Date (ADBA)	Actual Date
TBM Mining Starts	September 1, 2006			September 1, 2006
TBM Completion Date	August 15, 2008	April 28, 2011		March 30, 2011*
Substantial Completion Date	October 9, 2009[48]	June 15, 2013[49]	July 2, 2013	March 9, 2013
Final Completion**	December 8, 2009	August 12, 2013	March 2014	March 6, 2014

* TBM mining was essentially complete on March 22, 2011 when the TBM was stopped a short distance from the inlet in preparation for a ceremonial "breakthrough event" on May 13, 2011. For contractual purposes, the completion date was certified as March 30, 2011.
** Final completion is an OPG internal date, and was not part of the ADBA.

The ADBA contractual Substantial Completion date of June 15, 2013 was changed to July 2, 2013 in Amendment 1 to the ADBA (June 29, 2012). This change was in accordance with the agreed target cost and schedule adjustments pre-defined for the Major Risk Event "Crown Overbreak" listed in Appendix 5.3C "Major Risk Table" of the ADBA. ADBA Amendment 2 (October 16, 2013) further modified the contractual Substantial Completion date to October 4, 2013. These changes were to reflect the effects of "fall of ground" events on September 11, 2009 and July 2, 2011, which were deemed to have resulted in an aggregate delay of 94 days.

Strabag was able to achieve a three-month earlier Substantial Completion date than had been planned in the ADBA. This was through a change in the approach to removal of some of the tunnel lining equipment. Rather than waiting to remove grouting and arch concrete carrier equipment from the intake end, which would have required keeping the cofferdam intact, Strabag determined that it was feasible to disassemble, back up and remove this equipment through the outlet end. This allowed the intake service gates to be closed in the fall of 2012, thereby permitting watering up of the inlet area in November 2012. This in turn permitted earlier removal of the cofferdam, so that tunnel operation could begin in the spring of 2013.

[48] This was a contractual date with Strabag. The Board-approved in service date, which included a schedule contingency, was June 2010.

[49] The Board-approved in service date for the Superseding Business Case, including the new schedule contingency, was December 2013.

5.4 Capital Cost

The Project estimates and actual costs (all costs in $M) were as follows:

Table 5.5

Item	Original Release	Superceding Release BCS	Dec 2015 Final Cost
OPG Project Management	4.4	6.0	4.7
Owner's Representative	25.4	40.4	36.1
Other Consultants	4.0	5.9	6.5
Environmental/Compensation	12.0	9.6	8.7
Tunnel Contract (including incentives)*	723.6	1,181.7	1,107.7
Other Contracts/Costs	78.9	69.8	66.1
Interest	136.9	286.6	234.5
Total Project Capital	985.2	1,600.0	1,464.2

* Excludes Removal Costs of $1.6 M for the Dewatering Structure and $3.0M for the Acceleration Wall charged to OM&A

The final Project cost includes $60 million paid to Strabag for the interim and substantial completion fees and the schedule performance incentive. The final cost is 49% more than the originally approved (2005) estimate, but is 8.5% less than the total approved in the Superseding BCS. All contingency used prior to the Superseding BCS was included as cost in the ADBA Target Cost. Of the $164M contingency amount contemplated in the Superseding BCS, $49M had been spent at Project completion. The OPG, OR and other consultant costs of $47.3 million make up slightly more than 3% of the total Project cost. This is somewhat lower than the normally expected range of 5 – 10% for project management of large capital projects.

5.5 Changes

Project records indicated that the Contractor as well as OPG and the OR managed changes in accordance with the contract requirements and the Project change management procedure. A project management audit conducted by OPG Internal Audit in 2010 did not report any negative findings regarding Project scope and change control.

Five amendments to the original DBA were issued between March 2006 and September 2008. The first of these amendments dealt primarily with the constitution and operation of the DRB. The second amendment was to transfer responsibility to the Contractor for the consequences of their decision not to use a grout curtain to restrict groundwater inflows during excavation of the channel at the outlet end of the tunnel (PCN1, PCD2). Amendment three dealt with several PCN claims related to Differing Subsurface Conditions affecting the excavation and construction at the intake and accelerating wall area. These were settled in October 2007 at a total cost of approximately $7.5 million, vs. the original claimed amounts totaling nearly $20 million.

Amendment four included some further modifications to the DRB operation as well as addressing 13 PCDs that represented approximately $418,000 in net cost increases for work at the intake end. Amendment five added the definition and operational rules around "deemed amendments" to the contract, and also addressed seven PCDs with a total cost impact of $219,000.

In total, the Contractor submitted 25 PCNs prior to the ADBA many of which were settled through the DBA amendments described above. However, a number of these PCNs, particularly PCN17, were related to the Differing Subsurface Conditions encountered during tunnel boring, including the fall of ground in May 2007. The DSC issues were the primary causes of the cost claims and schedule delay that lead to the renegotiation of the contract. Twelve PCNs were dispositioned through the $40 million settlement (PCD33) associated with negotiation of the ADBA.

The ADBA was amended three times: in June of 2012; October of 2013; and February of 2014. The changes included in the first two ADBA amendments, as well as "deemed amendments", were as follows:

Table 5.6

PCD	Change Type	Amendment* ➘	Subject	Target Cost Change
35	Owners Mandatory Requirements	1	Change to intake and outlet gate material (stainless steel components specified)	$133,986
36	Deemed		Removal of tunnel sump pump at low point	($92,843)
37	Scope	1	Purchase of spare TBM main bearing	$1,746,952
38	Deemed		Decommissioning of boreholes	$92,843
39	Deemed		Disputed difference in pre-effective date loss (Outcome of dispute resolution)	$0
40	Deemed		Temporary ventilation shaft near Stanley Ave.	$0
41	Deemed		Change of full surface leak detectable waterproofing system for the tunnel arch	$0 (expected cost saving of $3.5 million)
42	Scope	1	Supply, installation and monitoring of profile monitoring instrumentation at the Rankine Generation Station (to monitor horizontal rock movement during tunnel excavation)	$185,000
43	Security Document	2	ILF Specified Professions Professional Liability Insurance	$0
44	Deemed		Additional site areas made available to the Contractor	$0
45	Scope	1	Drilling and sampling in the tunnel for potential swelling at low point study by K.Y. Lo	$185,000
46	Change in Law	1	Harmonized Sales Tax (provision to adjust cost after elimination of ORST)	($2,485,671) (2010,2011)
47	Scope	1	Engage Robbins in design of TBM main beam repair (December 2010 event)	$0
48	Risk Events	1	Crown overbreak adjustment (per ADBA)	$10,454,848
49	Scope	1	Return of spare TBM main bearing	($1,527,120)
50			*Appears not to have proceeded beyond a draft*	
51	Owners	1	Outlet gates: Welding receptacles, utility outlets, and	$19,115

PCD	Change Type	Amendment* ➘	Subject	Target Cost Change
	Mandatory Requirements		secondary control panel	
52	Deemed		Removal of asbestos cladding from the water main suspended from the PGS dewatering structure	$57,800
53	Deemed		Dewatering structure	$0
54	Deemed		Change in flow testing from tracer transit time to ultrasonic flow testing; reduce number of piezometers from 4 to 2.	$0
55	Other	1	Settlement of Dufferin Construction claims with Strabag for intake channel walls and outlet structure	$76,000
56	Other	1	Dufferin claim for stand-by and double shift work for PGS dewatering structure removal	$167,657
57	Scope	2	Submit plan for disposal of surplus goods, and provide inventory of surplus goods	$0
58	Other	2	Additional costs for intake and outlet gate installation	$2,956,238
59	Other	2	Additional costs for settlement with Dufferin related to delays in outlet rock plug and ramp removal	$2,151,164
60	Scope	2	Purchase of spare flow meter console	$23,477
61	Scope	2	Travel restraint system on approach wall, INCW parking lot extension, boat ramp grading	$281,924
62	Other	2	Adjust target cost for July 2, 2011 fall of ground	$12,442,640
63	Other	2	Adjust target cost for Sept 11, 2009 fall of ground	$2,000,000
64	Other	2	Adjust target cost for inflation relative to baseline (per ADBA)	$2,130,652
65	Other	2	Adjust target cost for diesel price relative to baseline (per ADBA)	$1,723,150
66	Other	2	Adjust target cost for design work relative to baseline	$2,133,300
67	Other	2	Maintenance bond	($450,000)

* Where no amendment number is shown, the deemed amendment was not written into the subsequent formal ADBA amendment document.

Target Cost adjustments totaled $9,003,567 for Amendment 1 and $23,450,528 for Amendment 2.

Amendment 1 to the ADBA also changed the Target Substantial Completion Date from June 15, 2013 to July 2, 2013 as part of the adjustment for the crown overbreak risk event (PCD048). Amendment 2 again adjusted the Target Substantial Completion Date from July 2, 2013 to October 4, 2013 based on the total 94-day delay attributed to the fall of ground events in September 2009 and July 2011. However, the actual Substantial Completion Date was achieved on March 9, 2013, considerably before the adjusted target date.

The original ADBA required the Contractor to provide a Letter of Credit, to cover the cost of any tunnel performance shortfalls or Contractor defaults, which was to be in effect until the Final Completion date (effectively the date on which *all* work was to be done.) The ADBA also required the Contractor to submit a Maintenance Bond to guarantee the cost of any required warranty work over the period of one year after

Substantial Completion (the date on which the facility was ready to use.) Amendment 3 eliminated the requirement for the Maintenance Bond but extended the duration of the Letter of Credit to cover any outstanding obligations.

The contract with HMM was amended in August 2010 to increase the value from $23.32 million to $47 million, to provide OR services for the remaining, extended duration of the Project. Actual final OR costs were well within the amended limit.

5.6 Quality

5.6.1 Performance

Tunnel flow testing was performed to verify that the contractual Guaranteed Flow Amount (GFA) of 500 m^3/s had been achieved. Alden Research Laboratory, a US firm, carried out the tests under subcontract to Strabag in July 2013.

The test apparatus included temporary water level gauges installed in the intake channel and outlet canal, and ultrasonic flow measuring transducers at the outlet of the tunnel, just upstream of the outlet gate structure. The multipath ultrasonic flowmeter measured flow by sending pulses between pairs of transducers located on opposite walls of the tunnel. Data was captured and recorded in real time through a wireless internet-enabled system. After a one-hour period to stabilize flow through the tunnel, water level and flow rate data was recorded for a 100-minute period early in the morning of July 24, 2013.

The test results were as follows:

Table 5.7

Average Upstream Water Level	170.99 m
Average Downstream Water Level	164.78 m
Average Flow Meter Reading	503.94 m^3/s
Performance Test Flow Water Amount (PTFWA)	495.1 m^3/s

The "Performance Test Flow Water Amount" (PTFWA) as defined in the ADBA[50] was the flowrate calculated by Alden for contractual guarantee purposes by adjusting for changes in the reference hydraulic head, in this case 5.6 m, due to the geometry of the outlet canal. The formula for this calculation was given in the ADBA.

The ADBA allowed for a difference of +/- 2% of the PTFWA (i.e. 9.9 m^3/s) from the GFA before any performance incentives or disincentives would apply. Since the PTFWA was within this 2% tolerance, the flow performance objective was met and no liquidated damages or bonuses applied to the contract.

[50] No change was made between the original DBA and the ADBA regarding the guaranteed flow.

5.6.2 Construction Quality

Initially there were some issues with the implementation of the Strabag and subcontractor quality programs, leading to replacement of some Contractor quality management staff. Generally, however, OPG Project staff expressed satisfaction with the overall final quality of the Contractor's work.

Early in the Project while the OR performed the quality oversight function, OPG was advised of nonconformances but was generally copied on formal nonconformance notices (NCNs) only after they had been closed out following disposition by the Contractor and OR. Disposition actions could include repair, replace, or use "as is".

An OPG internal audit conducted in June 2010 noted that although the OR was closely monitoring the quality of the Contractor's work there was "no structured reporting from the OR to the project team or in the Monthly Report to record recurring problems, the extent of condition, and corrective actions of permanent works." In response, OPG and the OR increased the detail of quality reporting and introduced quality trending to better track recurring problems.

Over the course of the Project, 68 Nonconformance Notices were issued. These can be generally categorized as follows:

Table 5.8

Work Area/Activity	No. of NCNs
Concrete quality and placement	26
Intake area – accelerating and approach walls	13
Dewatering System - shaft location, installation	9
Waterproofing – membrane problems	4
Outlet area	4
Shotcrete	3
Grouting	3
Other (tunnel alignment, support rings, blasting, etc.)	6

For 24 of the NCNs the disposition action was to use "as is". For the remainder, remedial action such as repair or replace was required and completed.

One significant problem, that could potentially have affected the 90 year service life of the tunnel – a key Project objective - was identified in 2009 and is briefly described below as an indication of the investigation and problem solving approach used for resolving quality issues.

In October 2009, when TBM mining was approximately 50% complete, a routine tunnel inspection indicated that water had migrated down the tunnel and leaked into a void between the invert concrete and the tunnel wall, in the vicinity of the tunnel low point about 1400 m from the outlet end. The trapped water was observed exiting from the water release holes and also from radial construction joints. The water from the release holes was saline which indicated that fresh water from the upper formations was traveling through the salty Queenston formation, most likely along the shotcrete boundary or deeper within the fracture zone around the tunnel excavation. Moisture could also be seen on the tunnel shotcrete walls (final arch concrete installation had not yet started) at various locations along the tunnel within the Queenston formation despite this formation being highly impermeable and dry. This indicated that water was present on both sides of the waterproofing membrane. The issue was formally communicated to Strabag by OPG in November 2009 through "Notice of Defective Tunnel Facility Project No. 001."

The water was removed from the affected section of the tunnel and a system of drains, sumps and pumps was installed to prevent further infiltration of water into the Queenston Shale under the invert. The invert was repaired by removing the cracked areas by intersecting core holes and installing non-shrink concrete with a strength at least equal to that of the liner concrete. Repair costs for this work were Disallowed Costs under the ADBA.

This event raised several concerns that fresh water leakage could potentially have compromised the integrity of the invert liner membrane and resulted in stresses on the tunnel from swelling of the surrounding rock due to the water penetration. It appeared that:

- The concrete invert liner had "floated", potentially allowing debris to enter between the concrete and the membrane; and
- The combination of movement of the concrete invert, trapped debris and loading from construction traffic could have damaged the membrane and comprised its ability to prevent water from leaking through the operating tunnel into the surrounding Queenston Shale.

After analyzing the alternatives and risks a decision was made to continue with tunnel construction, including installation of the membrane and arch concrete liner, while testing and analysis was done to assess the long-term impacts of the event. This work was done between 2010 and 2012.

K. Y. Lo Inc. was contracted to supervise the drilling and extraction of representative core samples of the Queenston Shale from the invert and side walls of the tunnel at the low point and to do testing to establish the swelling potential due to the water that had already infiltrated behind the membrane and the potential swelling that would occur if fresh water infiltration continued through holes in a damaged membrane. The testing confirmed that:

- Fresh water had infiltrated into the Queenston Shale;
- Chloride ion diffusion had occurred, reducing the salinity of the rock under the invert;

- The swelling process had started; and
- The effected swelling zone extended from the low point CH1+416 to CH1+720 and down approximately 1.2 m below the invert; a transition zone of partially affected rock extended from 1.2 to 1.8 m below the invert

ILF (Strabag's engineering subcontractor) then did a finite element analysis of the potential swelling loading from the Queenston Shale and concrete liner interaction under a number of load cases to establish the worst case conditions for continued swelling and the capacity of the concrete liner to resist the swelling loads over the design life of the tunnel. The OR later did its own analysis to verify the ILF findings.

MFPA Leipzig was contracted to carry out tests to determine if the membrane could have been damaged by the flooding, floatation of the concrete invert, and construction loading. This was followed by a series of tests to determine if the contact and interface grouting process could effectively seal the damaged membrane and restore the watertight barrier. This work was supervised by ILF and witnessed by the OR.

The two independent finite element analyses of the rock and lining interface showed that the as-built concrete liner had sufficient structural capacity, compliant with code requirements, to resist all the applied loads including the swelling loads derived from the K.Y. Lo swelling potential analysis. Tests on simulations of the as-constructed lining system showed that the contact and interface grouting would effectively seal the damaged membrane and prevent water penetration into the rock and therefore prevent chloride ion diffusion from the rock for all loading conditions for the design life of the tunnel.

Following the investigations and analysis it was concluded that the as-built tunnel liner, with the concrete invert repairs, complied with the Owner's Mandatory Requirements and applicable code requirements. Therefore, although it cannot be conclusively demonstrated at this time, it would appear that the 90-year service life for the Tunnel will be achievable.

5.7 Community Impacts

One of the key requirements of the Niagara Plant Group, as the ultimate user of the completed facility was to maintain a good working relationship with stakeholders, contractors and the affected public. The following table shows the outcomes observed versus the measures established as part of the related Project objective:

Table 5.9

Measure	Outcome
Zero Treaty violations concerning Falls flow	No violations
Zero International Niagara Board of Control (INBC) Directive violations concerning Grass Island Pool (GIP) operation	No violations
Zero ice management incidents	No incidents

Zero forced outages at existing diversion and generation facilities	No forced outages
Optimal planned outages coordinated with Niagara Plant Group outage plans	Achieved. Removal of the PGS dewatering structure was coordinated with a planned outage
Maintenance of positive relationships with regulators and host communities	Niagara Plant Group staff reported that this objective has been met. Planned and coordinated communications, and operation of the Community Liaison Committee were instrumental in achieving this.
Maintenance of ISO 14001 registration	Maintained
Maintenance of BSA 18000 registration.	Not applicable. OPG no longer maintains BSA18000 registration.
Minimize ongoing (post-project) monitoring requirements by NPG	No ongoing obligations will remain after ground water monitoring is completed in 2014. Removal of excavated materials stored on site (e.g. for brick making) will be a long term process.

6 Risk Events

The following table shows actual outcomes against the major Project risks identified in the original (2005) business case.

Table 6.1

Risk	Potential Consequences	Outcome
The Contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR)	Unexpected, adverse subsurface conditions could slow tunnel construction and require the Contractor to undertake remedial / extra work resulting in legitimate claims for extra costs and / or schedule extension for differing subsurface conditions (DSC).	Mining the Queenston Shale proved to be more difficult than anticipated due to the high horizontal stresses in the rock. Following resolution of a DSC claim, the Design-Build Agreement had to be amended to provide the Contractor with cost and schedule relief. The consequence was an increase of $479 million (49%) in the final Project cost vs. the release estimate, and a delay of 41 months beyond the original contractually agreed 50-month schedule to Substantial Completion.
OPG resources with knowledge and experience required for design and construction of a major tunnel are severely limited.	OPG resource limitations could have significant impacts on Project quality, cost and schedule.	Use of Hatch Mott MacDonald as the Owner's Representative, who provided most of the project and construction management resources, effectively mitigated this risk to the extent possible.
Queenston Shale, the host rock formation for the majority of the tunnel, has swelling properties when exposed to fresh water.	Swelling of the Queenston Shale surrounding the tunnel could over-stress the tunnel lining and cause damage that would interrupt flow through the tunnel and require expensive remedial work.	The tunnel incorporates an impermeable membrane and prestressed concrete/grout liner that have been designed and tested to prevent leakage of water from the tunnel into the surrounding rock. One leakage event occurred during construction, resulting in potential swelling of the Queenston Shale at the tunnel low point. Extensive testing and analysis following the event concluded that the liner design meets all design requirements, even with a potentially damaged membrane.

Risk	Potential Consequences	Outcome
Design / Performance criteria not met	The constructed tunnel may not meet design / performance criteria such as the guaranteed water flow capacity, accommodation of swelling of the host bedrock, particularly Queenston Shale, or design for a 90-year service life.	Flow capacity has been tested and verified to meet the guaranteed amount. Long term resistance to swelling of the Queenston Shale as well as ultimate service life are unknown at this time.
Serious construction accident	There are many safety hazards associated with tunnel construction that need to be identified and appropriately managed (steep grades, slips and falls, falling objects, water hazards, confined space, truck traffic, operating machinery, noise, dust, etc.)	13 High MRPH or equivalent incidents occurred. There were no work-related fatalities during construction. Reported LTI frequency was below the industry average for heavy civil construction projects. There were several bone fractures and one serious burn incident, but no life-threatening injuries.
Public safety and security	Risk of incidents, accidents and potentially fatalities to unauthorized persons entering the construction site and gaining access to areas and activities having High MRPH hazards.	Security measures were generally effective. There were 7 site intrusion incidents of which 3 involved thefts of construction materials. There were no injuries to anyone who gained unauthorized access to the site.

The following table shows the outcomes against the OPG Key Risks[51] that were monitored during the ADBA period:

Table 6.2

	Risk	Potential Consequences	Outcome
1	Major TBM breakdown including main bearing failure	Construction delay	Spare TBM main bearing was procured but was not needed and was returned for credit. A crack in the TBM main beam in December 2010 resulted in a shutdown of three weeks. However, overall mining completion date was not delayed.
2	Main conveyor failure	Construction delay	Risk did not occur
3	Inundation of tunnel after TBM breakthrough due to breach of cofferdam	Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities	Risk did not occur
4	Critical marine work (cofferdam removal) impeded by marine operational constraints (ice conditions) at INCW	Construction delay	Risk did not occur. Change in Contractor’s plan allowed for early removal of cofferdam before ice became a problem.
5	Tunnel collapse due to inadequate design or construction or ground conditions	Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities	Risk did not occur

[51] This list represents risks under active management as of late 2012. As noted in Section 4.6.3 the Key Risks were, in general, a higher-level summarization of the earlier detailed risk register.

	Risk	Potential Consequences	Outcome
6	Delay in removal of outlet plug due to OPG inability to provide a PGS outage when required	Construction delay	Risk did not occur
7	Profile restoration delayed due to prototype operation for restoration equipment and delays in procurement and delivery of equipment	Construction delay	Profile restoration was completed in Sept 2012, 164 days later than the original ADBA schedule. However, except for a brief period at the end of 2011, the slow progress did not have any impact on the subsequent arch liner installation activities.
8	Overall progress delayed due to the logistics of concurrent construction operations (TBM mining, invert concrete, profile restoration, arch concrete, grouting)	Construction delay	Risk did not occur. No delays as a result of overlapping operations.
9	Permanent works defective or do not conform with specifications due to construction quality (includes permanent works concrete deficiencies)	Cost increase and construction delay	Facility has been accepted. No evidence that this risk has occurred although there remains some probability that a defect could become evident later on.
10	Project costs increase due to contract management problems including claims and oversight of Contractor	Cost increase	Risk did not occur. Final cost was 8.5% less than approved in the Superceding BCS.
11	Contractor defaults on its obligations due to potential for significant loss	Cost increase and construction delay	Risk did not occur. ADBA was successful in motivating Contractor to achieve target cost and schedule.
12	Ground convergence exceeding specifications delays installation of the final concrete lining	Construction delay	Risk did not occur. Final lining was installed as planned.
13	Fire in tunnel due to hot works, faulty equipment, flammable gases and liquids, open flames, smoking	Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities	Four fire events in the tunnel were reported. One welding-related incident resulted in burns to a worker (LTI). A diesel compressor fire resulted in smoke inhalation by 5 workers fighting the fire, but no LTI. The other two fires were minor.
14	Major environmental/regulatory infraction due to reportable spill or discharge that results in a charge under federal or provincial legislation or regulations or under a municipal bylaw	Regulatory orders and charges, third party actions, reputational damage	There were no orders or charges against OPG. Regulatory risk was transferred to Strabag via the ADBA. MOE was concerned at one point in 2007 about number of exceedances.
15	Major safety incident due to construction related accident or work stoppage	Regulatory orders and charges, personnel injuries or fatalities, reputational damage	See section on safety outcomes.

	Risk	Potential Consequences	Outcome
16	Fall of ground due to inadequate design and/or construction of ground support and inadequate monitoring of convergence and support condition	Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities	Risk occurred. Two FOG incidents - in September 2009 and July 2011 - resulted in additional Allowed Costs for tunnel repairs and delays in the target completion date. However Substantial Completion (per ADBA) was not delayed. No injuries or fatalities occurred. The contingency approved in the Superseding BCS was sufficient to cover the costs of these events.
17	Arch concrete progress delayed due to initial setup delays and equipment failures during ongoing operation	Cost increase and construction delay	Risk did not occur
18	Pre-stress grouting progress delayed due to initial setup delays and equipment failures during ongoing operation	Cost increase and construction delay	Risk did not occur
19	Swelling of ground in the tunnel invert at the low point due to exposure to water	Cost increase due to rework	Some swelling did occur as a result of the event described in section 5.6.2; however, detailed analysis showed that the integrity of the liner has not been compromised. No related rework costs were incurred by OPG.
20	Loss of key Project personnel due to length of Project	Cost increase and construction delay	Risk occurred both within OPG and HMM. Succession planning was implemented and risk consequences were avoided.
21	Progress of final lining delayed by concrete delivery problems due to lack of a reliable off-site concrete supply that meets specifications	Cost increase and construction delay	Risk occurred early in the lining operation but did not affect the overall schedule.

The original Business Case identified a number of business-related risks as repeated in the table below along with the current outcomes:

Table 6.3

Risk	Potential Consequence	Outcome
Inability of OPG to fully recover the Project costs through the Regulated Rate	Adverse financial impact on OPG	The OEB approved recovery of $1,387M of the $1,464M total costs.
OPG has retained the hydrologic risk (uncertainty regarding Niagara River flow).	Incremental average annual energy output from the SAB complex could be less than 1.6 TWh resulting in a need to increase base load hydroelectric energy rates to recover Project	Energy output is now forecast to be 1.5 TWh

	costs.	
A successful claim by others in Canada or the United States to use Niagara River water available for power generation that exceeds OPG's capacity.	OPG could lose rights to use some of the Niagara River water available for power generation.	The NEA grants exclusive water rights to OPG. Successful completion of the tunnel ensures continuing rights to the water.
The 1950 Niagara Diversion Treaty is now subject to renegotiation following a 1-year notice period.	The government in either Canada or the United States could pursue renegotiation of the 1950 Treaty to address issues raised by other stakeholders that could result in a reduction of flow available to OPG for power generation at the SAB complex.	Risk has not yet occurred

7 Project Closeout

As of the date of this PIR, the Project has been placed 100% in service, but has not yet been formally closed out. Some final documentation is still outstanding. Also, the flowmeters installed in the tunnel have apparently failed, although the reason for this is not known.

8 Lessons Learned

A facilitated Project lessons learned meeting was held in April 2007 with OPG and HMM Project staff to discuss and document experiences with the first phase of the INCW Part Project. Much of the discussion centred on the safety management aspects of the work, for which OPG was the Constructor. Some of the key observations from this meeting were that:

- Job Safety Analyses were a new tool for some of the subcontractors but by having OR-prepared JSAs provided as examples, the subcontractors were able to more easily adopt the methodology;
- Work protection training for the subcontractor workers should have been more site-specific;
- Having OPG Niagara River Control Centre staff coordinate the work protection process, and having the OR hold work protection, had been effective;
- During visits MOL inspectors would apply codes and standards other than those from the Construction Regulations[52] when issuing orders, and in some cases would write orders without fully verifying the requirements; and

[52] This practice was not unique to MOL inspections of the Niagara Tunnel Project. It has been applied on other OPG work sites in the past.

- The handoff from the Part Project from Constructor back to Owner Only status required some improvement to facilitate a smoother transfer.

A second formal facilitated lessons learned meeting was held in July 2013 after the tunnel had been placed in-service. The full list of lessons gathered in that meeting is shown in Appendix D.

Some additional observations and recommendations regarding lessons from the Niagara Tunnel Project follow:

8.1 Contracting Method

At the outset of the Project there was a strong desire on the part of the OPG Board and senior management to a) transfer as much of the risk in the Project as possible to the Contractor, and b) obtain as much up-front price and schedule certainty as possible. This was understandable at the time, given the lack of recent OPG experience with tunneling projects and the need to re-establish confidence in OPG's ability to manage a major project without significant cost or schedule overruns. The original strategy for allocation of the DSC risk and to provide a basis for a fixed price contract was to establish with the Contractor the agreed Geotechnical Baseline Report C that would define the expected subsurface conditions and to rely on an independent Dispute Review Board to adjudicate any claims arising from differing conditions. The probability and cost/schedule impact of encountering much more adverse conditions were, in hindsight, underestimated by both the Contractor and the OPG/OR Project team to the extent that the original Project contingencies for these events were inadequate. In the end, the risk-sharing mechanism later adopted for the ADBA was a more cost-effective way of dealing with this type of risk than the original approach. Some key features of the ADBA that contributed to its success were:

- Establishment of a detailed cost estimating model agreed on by both parties for the remaining portion of the tunneling work, which could form the basis of the contract Target Cost. One important element of this model was the use of different productivity rates[53] for different rock conditions. Another element was the use of baseline costs for certain items such as escalation and the cost of diesel fuel where there was some uncertainty or disagreement about future costs. Adjustments for actual costs could then be made with reference to the agreed baseline. As work under the ADBA continued the detailed estimating model also provided a tool for calculating accurate projections of the forecast cost to completion;
- Pre-defining what would be considered Allowed or Disallowed costs. In particular, the costs of rework due to Contractor quality issues that were found

[53] It might be argued, of course, that even under the original DBA these productivity rates could not have been known in advance of the actual work. However, an up-front agreement on *expected* rates, with an adjustment mechanism, could still have formed the basis of a target cost.

by the OR were defined in the ADBA as Disallowed costs. This provided a strong incentive for an effective Contractor quality control system;

- Establishing an equitable method for sharing the risks and benefits of deviations from the Target Cost and Target Schedule. This included sufficient incentives to encourage innovation and productivity as well as disincentive limits that would avoid unacceptable losses to the Contractor, thus ensuring that the Contractor would not default and the work would be completed;
- Pre-defining important risk events, such as excessive overbreak, that could occur with an associated unit cost mechanism for a fair adjustment of the Target Cost and Schedule for the work;
- A requirement for OPG pre-approval of Contractor materials and services with a cost of more than $100,000. This was intended to help ensure that the Contractor was applying value for money principles when making major purchases for the work; and
- Use of “open book”, audited cost monitoring with the Contractor. This allowed OPG to verify that all claimed costs were in fact legitimate.

It should be noted that those portions of the work that were considered well-defined and relatively low risk, such as the intake and outlet structure civil works subcontracts, remained fixed-price components of the overall contract and were not subject to all of the additional provisions listed above.

Although not perfect, the ADBA should prove to be a valuable template for OPG to adapt and use for future contracts of this type.

8.2 Risk Management Strategies

To avoid the temptation to assume that Design-Build or fixed price contracting with liquidated damages are automatically the best risk-limiting strategies for future projects, OPG should ensure that a wider range of contracting options and strategies is systematically examined, *before* deciding on a final approach. This would allow the benefits and risks of each option to be compared in the context of the overall objectives and priorities of the project. One effective method for doing this would be to use the Project Delivery and Contracting Strategy (PDCS)[54] tool developed by the Construction Industry Institute. This tool provides a means of comparing the effectiveness of different strategies in meeting a prioritized list of Owner-defined project objectives.

The practice of sharing non-commercial risk information with the DB Contractor, required by the insurance underwriters, was effective in promoting more open communication between the parties with respect to both risk identification and risk mitigation. This approach also ensured that the responsibility for risk management was clearly assigned and accepted. Involving major contractors directly and as early as

[54] CII Publication RS165-1 – Owner’s Tool for Project Delivery and Contract Strategy Selection

possible in risk management activities is a practice that should be considered for all projects.

The use of Excel® as the tool for risk management for the NTP had several drawbacks, including:

- Multiple versions of the risk registers had to be created for different analysis, tracking and reporting purposes;
- It was difficult to track the history of risk management activities, e.g. when risks were identified, if/when they actually occurred, when they were closed and, when mitigating actions were completed, etc.; and
- Risk registers did not provide a means to differentiate between risk owners and those responsible for risk mitigation activities (they may not have been the same individuals).

For future major projects it would be highly desirable to procure and use a project risk management database tool[55] as the single repository for all project risk information. Customized risk reports could then be generated for different purposes and audiences.

8.3 Safety and Environmental Management

Through the Owner Only structure for the NTP, OPG was able to effectively contain its exposure to risks associated with construction health and safety and some environmental aspects of the Project. However, the Contractor's management of risks to worker safety and the environment was, at best, only satisfactory. In addition to requirements to conform to applicable recognized international standards a number of contract terms and conditions might be considered to improve conformance to OPG's expectations on future major projects, even under an Owner Only arrangement:

- Mandate (and be prepared to pay for) a specified minimum number of full time on-site staff to oversee health and safety and environmental management;
- Require the contractor to demonstrate through records of experience and qualifications that health and safety and environmental management staff have the requisite competence to meet minimum requirements defined by OPG;
- Mandate a contractor project team reporting relationship that prevents giving a higher priority to production than to health and safety and environmental management. Ideally, to maintain the required level of influence, contractor health and safety and environmental management staff should not report directly to, but have only a "dotted line" reporting relationship to, the contractor project manager;
- Provide a contractual mechanism for periodic meetings between OPG and contractor senior management (above project level) to discuss contractor performance and continually reinforce OPG's expectations; and

[55] This type of tool would have to be chosen specifically for project management purposes and would not be the same as an *enterprise* risk management system.

- Require at least annual independent, third party audits of the contractor's health and safety and environmental management systems *as applied to the specific project*, with payment-related timelines for rectification of non compliances and verification of corrective actions (i.e. portions of progress payments to be withheld until compliance can be satisfactorily demonstrated).

9 Conclusions

The Niagara Tunnel Project was ultimately successful in providing a facility capable of delivering the required additional flow of 500 m^3/s to the SAB complex. The final Project cost was 8.5% less than the revised target approved in the Superseding Business Case, and the Project achieved Substantial Completion 14 weeks ahead of the revised contract Target Schedule date. Therefore, only 19% of the approved cost contingency, and none of the schedule contingency, was required.

Risk management for the Project was carried out in conformance with established governance as well as generally accepted best practices for both qualitative and quantitative assessments. Risk mitigating actions were defined and completed as planned for anticipated events. An independent expert concluded that the geotechnical investigations undertaken prior to the Project were "professionally complete and met or exceeded in some cases the professional standards for work of similar type and magnitude[56]." Therefore the schedule delay and additional costs of the Project – with respect to the original 2005 Business Case approval - were due almost entirely to the unexpectedly difficult and unforeseen subsurface conditions within the Queenston Shale formation. It was these conditions that resulted in extensive crown overbreak, leading to lower TBM mining rates and the need to re-profile the tunnel prior to installation of the final liner.

OPG and the OR have expressed satisfaction with the final design and construction quality of the facility provided by the Contractor. The Contractor's safety and environmental management performance was acceptable.

An important objective of the Project was to maintain the good community and stakeholder relationships that the Niagara Plant Group had established over the years. Despite the scale and duration of the Project, this objective was successfully met.

A review of the project management system applied on the Project, which has been only briefly summarized in this report, demonstrated that its planning and execution was consistent with the Project Management Body of Knowledge (PMBOK) published by the Project Management Institute. In addition OPG and the OR employed a number of general recognized project management "best practices" (e.g. pre-project planning, PDRI, team building, dispute resolution, etc.). Overall, the Project was managed in a

[56] Ilsley, Roger C., "Niagara Diversion Tunnel Report – Prepared for Ontario Power Generation", 9 September 2013.

very competent and professional manner, with a high level of teamwork and cooperation maintained between all participants despite the challenges encountered. A good working relationship between the parties from the outset of the Project facilitated negotiation of a mutually acceptable Amended Design-Build Agreement avoiding a lengthy and expensive contract dispute.

Abbreviations and Acronyms

ADBA	Amended Design-Build Agreement
BCS	Business Case Summary
CIA	Community Impact Agreement
CPI	Cost Performance Index
DB	Design-Build
DBA	Design-Build Agreement
DRB	Dispute Review Board
DSC	Differing Subsurface Conditions
EA	Environmental Assessment
FOG	Fall of Ground
JSA	Job Safety Analysis
MNR	Ministry of Natural Resources
MOE	Ministry of the Environment
MOL	Ministry of Labour
NCR	Non Conformance Report
NRHD	Niagara River Hydroelectric Development
OPA	Ontario Power Authority
OR	Owner’s Representative
PCD	Project Change Directive
PCN	Project Change Notice
PDRI	Project Definition Rating Index
PEP	Project Execution Plan
PRM	Project Risk Management
RFI	Request for Information
RFP	Request for Proposal
SPI	Schedule Performance Index
TBM	Tunnel Boring Machine

References

Note: While in some cases the originating organization is shown, specific author names/affiliations are not provided because in most cases there were either multiple authors, or, author names were not shown on the documents. Similarly, many documents reviewed did not have a Document Number assigned.

Document Title	Document Number	Date
Business Case Summary Niagara Tunnel Project Full Release for Niagara Tunnel Project (EXEC0007)		28-Jul-05
Business Case Summary Niagara Tunnel Project Niagara Tunnel Project (EXEC0007) May 2009 Superseding Release for Niagara Tunnel Project (EXEC0007)		21-May-09
Recommendation for Submission to the Board of Directors Niagara Tunnel Project		21-May-09
Capital Expenditures - Niagara Tunnel Project (OPG submission to OEB)	EB-2013-0321 Exhibit D1 Tab 2 Schedule 1	27-Sep-13
Niagara Tunnel Project Completion Report Draft (HMM Report)	NAW130-00121.05, ID0056	1-Dec-13
Niagara Tunnel Project Monthly Report Executive Summary (Reports No. 1 to No. 96)		October 2005 to September 2013
The Niagara Tunnel Project Project Execution Plan R0	R-NAW130-00121-0001	8-Apr-05
The Niagara Tunnel Project Project Execution Plan R1	R-NAW130-00121-0001-R1	27-Mar-06
The Niagara Tunnel Project Project Execution Plan R2	R-NAW130-00121-0001-R2	1-Sep-10
The Niagara Tunnel Project Project Execution Plan R3	R-NAW130-00121-0001-R3	1-Jan-13
Niagara Tunnel Project Results of the October 1st 2004 Project Definition Rating Index Assessment (Memo)		6-Oct-04
Niagara Tunnel Project Results of the April 13th 2005 Project Definition Rating Index Assessment (Memo)		14-Apr-05
A Code of Practice for Risk Management of Tunnel Works (International Tunnelling Insurance Group)		Jan 30 2006
Niagara Tunnel Project OPG Risk Management Plan R01	R-NAW130-01900-0041	10-May-07
Niagara Tunnel Project OPG Risk Management Plan R02	R-NAW130-01900-0041	15-May-08
Niagara Tunnel Project OPG Risk Management Plan R03	R-NAW130-01900-0041	12-Aug-08
Niagara Tunnel Project Risk Management Plan R04	R-NAW130-01900-0041-04	1-Apr-12
Niagara Tunnel Project Qualitative Risk Assessment Report (Prepared by URS)		24-Feb-05

Document Title	Document Number	Date
Niagara Tunnel Project Quantitative Risk Assessment Report (Prepared by URS)		1-May-05
Quantitative Risk Assessment Niagara Tunnel Project	R-NAW130-01900-P	27-Jul-05
Niagara Tunnel Project Key Risk Plan R01		15-Oct-12
Niagara Tunnel Project Key Risk Register R15		9-Apr-13
Niagara Tunnel Project Quantitative Risk and Contingency Analysis (Memo)		12-Apr-11
Niagara Tunnel Project Schedule Assessment Workshop (Memo)		23-Jun-10
Niagara Tunnel Project Financial Model Review (Letter from Access Capital Corp.)		19-Aug-05
(DBA) Amendment Agreement Number 1		15-Mar-06
(DBA) Amendment Agreement Number 2		5-Jul-06
(DBA) Amendment Agreement Number 3		10-Oct-07
(DBA) Amendment Agreement Number 4		7-Nov-07
(DBA) Amendment Agreement Number 5		25-Sep-08
Dispute Review Board Report Niagara Tunnel Project, Dispute Review Board Dispute No. 1		30-Aug-08
Amended Design/Build Agreement Niagara Tunnel Facility Project Between Ontario Power Generation Inc. and Strabag Inc.		1-Dec-08
(ADBA) Amendment Agreement Number 1		29-Jun-12
(ADBA) Amendment Agreement Number 2		16-Oct-13
Owner's Representative Services Agreement Niagara Tunnel Project Phase II Ontario Power Generation Inc. and Hatch Mott Macdonald Ltd.		1-Sep-05
Amendment Agreement between Ontario Power Generation Inc. and Hatch Mott Macdonald		1-Jan-10
Niagara Tunnel Facility Project Project Change Notices as of June 3, 2013 (PCN Log)		
Niagara Tunnel Facility Project Project Change Directives as of June 3, 2013 (PCD Log)		
Niagara Tunnel Project - Reportable Spills (Excel file)		14-Jan-13
Health & Safety Incident Summary		2-Dec-13
Niagara Tunnel Facility Project Nonconformance Register		11-Sep-13
Niagara Tunnel Project - Quality Management Diligence Review (Memo from OPG to OR)	NAW130-01900 T5	1-Mar-12

Document Title	Document Number	Date
Report of Equipment in Service - Niagara Tunnel Project (EXEC0007)		10-Apr-13
Environmental Compliance Observations and Contractor Response	NAW130-07000.24-T5	30-Nov-11
Notice of Defective Tunnel Facility Project 001		12-Nov-09
Niagara Tunnel Project Low Point - Water Infiltration and Potential Swelling of Queenston Shale (HMM Report)	NAW130-00061.09 ID047 R-NAW130-29230-0114	1-Feb-13
Niagara Tunnel Facility Project Flow Verification Tests Final Results (Strabag/Alden)	R-NAW130-62900-0003 Rev 02	20-Sep-13
Audit of Safety Management - Niagara Tunnel INCW Part Project (Memo)		7-Sep-06
2007 Niagara Tunnel Facility Project Environmental Management Audit (Memo)		16-Nov-07
Internal Audit Niagara Tunnel Facility Project - Amended Design/Build Agreement		1-May-10
Internal Audit Niagara Tunnel Project, Execution Phase		1-Jun-10
Internal Audit Strabag Contract Audit		1-Oct-11
Internal Audit Niagara Tunnel Project (NTP)		1-Oct-12

Appendix A – Project Chronology[57]

Feasibility/Concept/Definition Phases

Date	Milestone / Event
1982-1987	**Comprehensive Conceptual Analysis** • Potential development alternatives analyzed • Geotechnical investigations conducted • Recommended the development of additional diversion and generation capacity at the Sir Adam Beck complex
08-Aug-1988	**Ontario Hydro Board Authorizes Project Definition Activities** • Included preliminary engineering and an environmental assessment
Mar-1991	**Ontario Hydro Submits Environmental Assessment ("EA") for Niagara River Hydroelectric Development ("NRHD")** • Proposed NRHD included two new tunnels, a three-unit 1050 MW underground generating station (referred to as Beck 3), and transmission improvements in the Niagara Peninsula • Allowed for staging of the project (i.e. the diversion facilities, one or both tunnels, could proceed in advance of the generation and transmission facilities)
22-Dec-1993	**Community Impact Agreement ("CIA") Signed** • CIA signed between Regional Municipality of Niagara, Town of Niagara-on-the-Lake, City of Niagara Falls and Ontario Hydro for tourism, road upgrades and facility improvements that would be necessary if the NRHD were to proceed • CIA was based on the full NRHD with estimated construction duration of 7 years and estimated peak construction workforce of 800
Feb-1998	**Ontario Hydro Initiates Review of Phase 1 of NRHD** • Decision to initiate Phase 1 (construction of one new tunnel)
Apr-1998	**Ontario Hydro Retains the Beck Diversion Group ("BDG") as the Owner's Representative for Project** • Acres International Limited, Bechtel Canada and Hatch Mott MacDonald comprised BDG
Jun-1998	**Ontario Hydro Solicits Bids for Phase 1 of NRHD** • Solicited bids for detailed design and construction of one new tunnel • Bids received in Sept-1998 and analyzed in Oct-1998 resulting in a recommendation for award
14-Oct-1998	**Complete NRHD receives EA Approval** • EA approval provided Ontario Hydro with the flexibility to undertake the development in phases
Dec-1998	**Ontario Hydro Delays Award of Contract** • Ontario Hydro informs bidders that given the imminent reorganization of the Corporation, the final decision regarding the tunnel would be deferred until after April 1999

[57] From OEB submission EB-2013-0321 Exhibit D1 Tab 2 Schedule 1

Date	Milestone / Event
Jun-1999	**OPG Decides to "Defer Indefinitely" the Project** • OPG decided to focus on other major projects (e.g., return to service of Pickering A) before committing to construct the new tunnel

Nov-2002	**Province States It Will Direct OPG to Proceed with New Water Diversion Tunnel** • The Province subsequently indicated a strong desire to have the project completed in the shortest possible timeframe
24-Jun-2004	**OPG Board of Directors Approves Preliminary Release** • Preliminary release of $10M to conduct a Request for Proposal ("RFP") process and to carry out such other preconstruction activities as OPG deems necessary
Jul-2004	**OPG Engages Hatch Mott MacDonald ("HMM")** • HMM, an international tunneling /mining expert consultant company, was engaged as OPG's Owner's Representative ("OR") for the Project • HMM to work in association with Hatch Acres
13-Aug-2004	**Request for Expressions of Interest ("EOI") Issued** • Request for EOIs for prequalification of potential proponents issued • Responses received by 09-Sep-2004 from seven companies and consortiums
Dec-2004	**Invitation to Submit Design/Build Proposals Issued** • Invitations issued to four pre-qualified proponents • Final Amendment (#5) issued on 26-Apr-2005
18-Feb-2005	**Agreement Signed Between the Niagara Parks Commission ("NPC") and OPG** • Agreement forms part of the larger Niagara Exchange transaction concerning the long term disposition of water rights on the Niagara River • Committed OPG to undertake remedial work at the retired Ontario Power and Toronto Power generating stations for reversion of these stations to the NPC and secured the agreement of the NPC that until 2056 it would grant water rights to no party other than OPG • Associated $10M settlement with Fortis Ontario, approved by the OPG Board on 08-Feb-2005, secured an irrevocable assignment of the water associated with Rankine generating station. These costs are included in the release estimate for the Project
13-May-2005	**Design/Build Proposals Received** • Three (3) proposals received • Proposals evaluated by separate commercial and technical teams
Jun-2005 to Jul-2005	**Proposal Evaluation and Negotiations with Proponents** • Based on evaluation scores, it was determined that negotiations should proceed initially with all three proponents to determine the "best value" proposal • When the proposals were re-scored after additional information was received and preliminary negotiations occurred, OPG began negotiating solely with the top two proponents • At the conclusion of the process, OPG chose Strabag AG as the successful proponent

28-Jul-2005	**OPG Board of Directors Approves NTP Execution Phase** • Niagara Tunnel Project approved with a budget of $985M and an in-service date of June-2010. • OPG Board approval subject to obtaining Provincial financing, through Ontario Electricity Financial Corporation, which was authorized on 18-Aug-2005

Execution Phase

Date	Milestone / Event
18-Aug-2005	**Design-Build Agreement ("DBA") Signed with Strabag AG**
Sept-2005	**Strabag occupies site and starts NTP construction**
17-May-2006 and 19-Jun-2006	**Strabag Issues Claims for Differing Subsurface Conditions ("DSC") for Underwater Construction at the Intake Channel and Acceleration Wall** • Initiation of a dispute regarding a DSC for excessive overburden on the river bed encountered during construction of the intake channel that was claimed to differ materially from the subsurface conditions described in the Geotechnical Baseline Report ("GBR") • DSC claim related to work at the acceleration wall where conditions (i.e. bedrock elevation and the presence of large boulders) were claimed to differ materially from the GBR
01-Sep-2006	**TBM Excavation Commences** • TBM was acquired and assembled within 12 months according to the schedule proposed by Strabag and incorporated into the DBA
23-May-2007	**Strabag Claims DSC for Adverse Conditions in the Queenston Shale** • On or about 16-May-2007 near 840 m, immediately below the Whirlpool sandstone formation, a large block of Queenston Shale dropped from the tunnel crown • Strabag claimed DSC relative to the GBR
20-Sep-2007	**Settlement and Release Agreements Covering the Intake Channel DSC Signed** • Addressed DSC for the Intake Channel and Acceleration Wall underwater construction • Settlement Agreement signed by OPG and Strabag • Release Agreement signed by OPG, Strabag, Dufferin Construction and McNally Construction
24-Oct-2007	**Strabag Initially Proposes a New Tunnel Alignment** • Strabag suggested a number of benefits of realignment including an improved tunneling process
05-Nov-2007	**Strabag Delivers Dispute Notice 001** • Dispute Notice 001 delivered to OPG concerning Strabag's DSC claim associated with "Collapse in the Tunnel Crown," signaling their intent to refer this matter to the Dispute Review Board ("DRB") as a complex dispute triggered by a DSC, under the process contained in DBA s 5.5(a) • OPG countered on 12-Nov-2007 by requesting that Strabag agree to have the DRB first decide whether DBA s 5.5(c) applies. That section states settlement of DSC's concerning differing rock support requirements should be addressed only upon completion of the tunnel excavation
04-Feb-2008	**Strabag Submits an Optimized Alignment & Revised Schedule Proposal** • Proposal also included information on alleged DSCs, efforts to mitigate DSCs, and implications to TBM drive and costs

14-Feb-2008	**OPG and Strabag Senior Management Decide to Obtain a Determination from the Dispute Review Board ("DRB")** • Determination requested from DRB concerning the merits and materiality of DSCs alleged by Strabag • DRB response would be considered by both OPG and Strabag to pursue further negotiations including finalization of commercial terms of the realignment

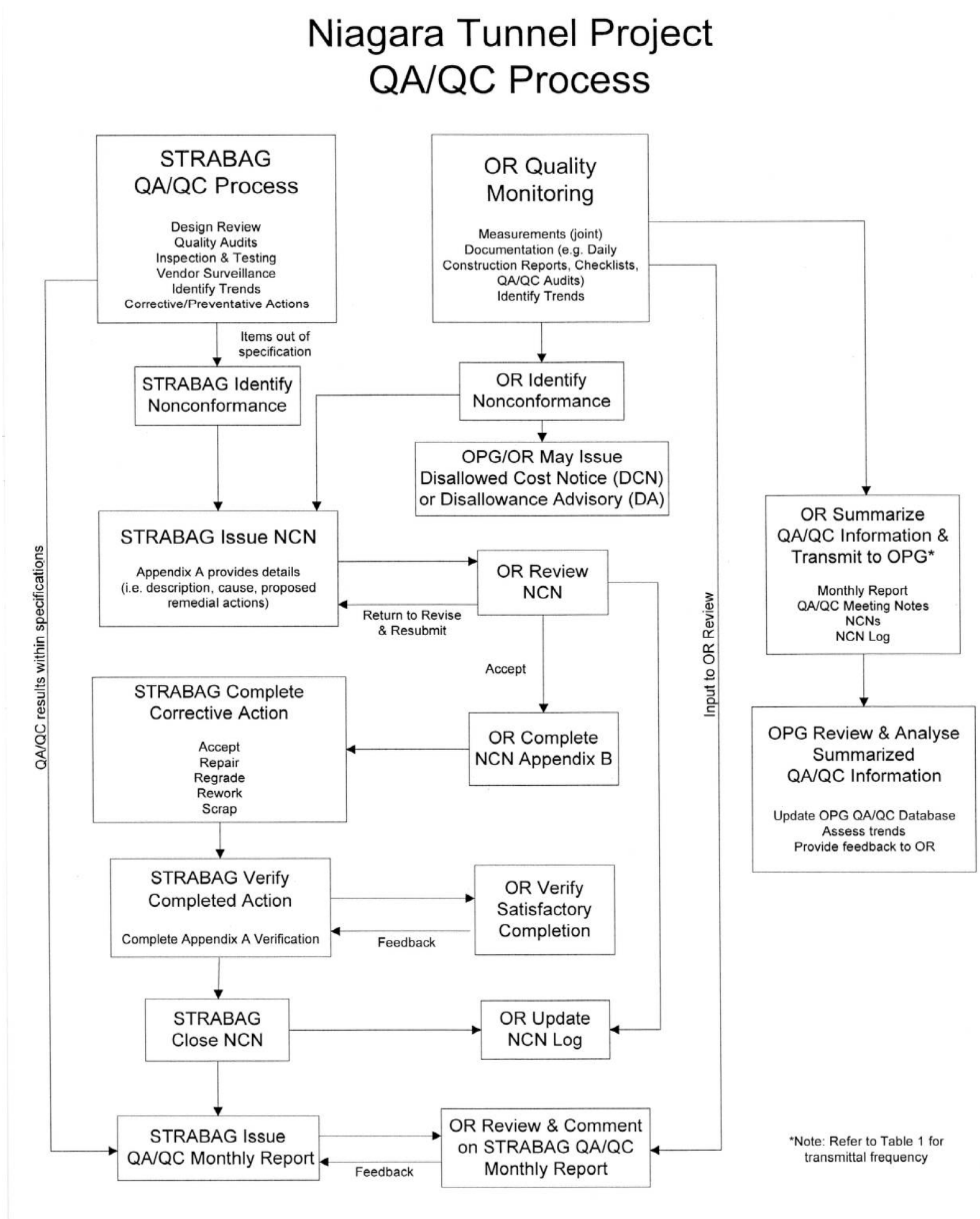
31-Mar-2008	**Ministry of Environment ("MOE") Accepts the Proposed Tunnel Realignment** • MOE accepts OPG request for a minor amendment to the approved EA regarding the proposed tunnel realignment
04-Apr-2008	**Strabag's DSC Position Summary Delivered to the DRB and OPG** • Initiated the DRB Hearing Process • OPG and Strabag position papers, including expert reports, were subsequently exchanged and delivered to the DRB on 23-May-2008. • OPG and Strabag rebuttal papers were exchanged and delivered to the DRB on 13-June-2008.
23-Jun-2008 to 26-Jun-2008	**DRB Hearing Held** • Due to the volume of materials to be considered and the complexity of the dispute, the DRB advised that their deliberations and written recommendations would likely require 60-90 days
30-Aug-2008	**DRB Report and Non-binding recommendations Received** • Report presents the DRB's unanimous conclusions and recommendations under five topics
09-Sep-2008	**Strabag Commences Horizontal Realignment of Tunnel** • Started at approximately CH2+980
Oct-2008	**OPG Management Recommends Pursuing a Negotiated Settlement with Strabag** • OPG evaluated options including engaging another Contractor to complete the Project and proceeding under the existing Design-Build Agreement • Negotiated settlement was determined to provide the greatest likelihood of completing the Project at the lowest cost in the shortest duration
11-Nov-2008	**Principles of Agreement Signed** • Negotiations were held from 15-Oct-2008 to 17-Oct-2008 and 03-Nov-2008 to 05-Nov-2008 • Outlined how the Parties would reach a final resolution of Strabag's claim of Differing Subsurface Conditions in the Queenston Formation
31-Dec-2008	**Strabag Starts Vertical Realignment of Tunnel** • Started at approximately CH3+300
09-Feb-2009	**Term Sheet Signed** • Negotiated Term Sheet required as part of the Principles of Agreement in order to further elaborate how the Parties would finalize the Revised Agreement to complete the Niagara Tunnel Project
24-Feb-2009	**Agreement on Revised Contract Schedule** • Substantial Completion date of 15-Jun-2013 with incentives and disincentives relative to target in-service date
07-Apr-2009	**Agreement on Target Cost** • Negotiations resulted in a contract Target Cost of CAD $985M with incentives and disincentives relative to the target cost
21-May-2009	**OPG Board Approval** • Board approves the revised schedule and cost, and the amendment and execution of the Amended Design-Build Agreement with Strabag
04-Jun-2009	**Amended Design-Build Agreement ("ADBA") Signed** • **Effective date of ADBA is December 1, 2008**

11-Sep-2009	**Fall of Ground between 3,605m and 3,625m** • Approximately 100 m^3 of Queenston Shale and temporary tunnel lining (shotcrete, wire mesh and steel channels) fell from the right side of the tunnel crown • Investigations concluded that a loosening of the rock support dowels put more pressure on the dowels' face plates than they could hold, which led to the fall. Boreholes NF-4 and NF-4A contributed to the loosening of the dowels by allowing relatively fresh water to penetrate and degrade the surrounding rock • Set back the schedule for NTP completion by approximately 17 days based on one day of delay to TBM mining translating into 0.375 days of delay to the critical path • Final cost impact of the 2009 fall of ground was estimated at $2 M, which is equal to insurance deductible, so no claim was made.

30-Mar-2011	**TBM Mining Completed** • Boring of tunnel complete • TBM disassembly and removal follows
02-Jul-2011	**Fall of Ground between 6,033m to 6,080m** • Approximately 1,200 m^3 of shotcrete, steel ribs, wire mesh and loose rock fell from the tunnel crown • Remediation costs initially estimated $17.6 M, including work done outside of the MOL mandated area, but later revised to $12.1 M. Insurer took the position that since the actual fall of ground area was less than 100 metres, a $10M claim limit applied and will pay this amount • ADBA Target Cost will be increased by $10.4M
25-Jul-2012	**ADBA Amendment No. 1** • Incorporated a number of Project Change Directives ("PCD"s), and recognized a number of PCD Deemed Amendments • Recognized budget transfers that have occurred without change to the Target Cost or to the scope of the Work • Amended Appendix 1.1(TTT)—Target Cost: o aggregate change of $90,003,566.91 to the Target Price resulting from the incorporated and recognized PCDs; o the revised Target Cost is about $994 M; and o revised allocation of the Target Cost for the purposes of cost control, cost projection and cost performances indices only. • Amended the Substantial Completion date to 02-July-2013 • Amended Appendix 1.1(hhh) - Project Change Directive Form • Amended Appendix 2.2(a) - Organizational Chart
30-Jul-2012	**Invert Concrete Lining Completed** • Decommissioning of invert shutter was completed by 15-Aug-2012
19-Sep-2012	**Profile Restoration Completed** • Decommissioning of restoration carrier/bridges was completed by 05-Oct-12
06-Nov-2012	**Final Concrete Lining Completed** • Arch concrete carriers were moved to the outlet for disassembly and removal by 31-Dec-2012
15-Nov-2012	**Cofferdam Flooded** • Intake stop logs were installed by 13-Nov-2012 and the cofferdam was flooded to permit removal

04-Feb-2013	**Grouting Operations Completed** • Contact grouting was completed on 10-Nov-2012, and the contact grout carrier was moved to the outlet for disassembly and removal by 30-Dec-2012 • Pre-stress grouting was completed on 04-Feb-2013, and the mobile pre-stress grout carrier was removed from the tunnel by 22-Feb-2013
09-Mar-2013	**Substantial Completion** After 24 hours of uninterrupted flow, the Substantial Completion milestone was achieved on 09-Mar-2013
24-July-2013	**Flow Test Completed** Flow test conducted by Alden Research confirms that tunnel flow rate meets contractual Guaranteed Flow Amount of 500 m^3/s (within 2% tolerance)

Appendix B – QA/QC Process



Appendix C – Key Risk Plan

Niagara Tunnel Project Key Risk Plan

R01

ID	Risk	Mitigation Detail	Residual Risk					Quantitative Analysis	Notes	Risk Owner & SME
ID #1	**CLOSED** **Major Tunnel Boring Machine (TBM) breakdown including main bearing failure** Due to: Risk ID #6.3 - Major TBM breakdown Risk ID#6.37 - TBM main bearing failure *Assumptions:* • Risk expires at the end of tunnel mining (scheduled for April 2011)	• Proactive maintenance program for the TBM and associated equipment • Maintenance 8-h shift/day • Regular oil sampling and testing • Regular inspections by remote camera • L10 life with sufficient safety factor for main bearing • Adequate critical spares, including spare main bearing • Procurement of spare main bearing and storage in Ohio • 24-hour servicing by experienced work forces including TBM manufacturer • Adjustment of thrust during mixed face boring conditions *Assumptions:* • L10 life means that if TBM operates/bores for 15,000 hours then there is a 10% chance of a bearing failure. Even though the project duration lengthened, the actual expected boring time remains at 6,000 hours and the likelihood of bearing failure is anticipated to be less than 10%. Residual risk depends on whether or not arch concreting operations are underway						*Monitoring mitigation:* • OPG and OR monitoring of spare main bearing availability. • OPG and OR monitoring of TBM maintenance. • OR monitoring of oil sampling and testing. *Monitoring the risk:* • On-going OR monitoring of TBM performance. *Performance metrics/ early warning signals:* • Oil analysis results, oil temperature, oil filter plugging *Assumptions:* • **[tbd]**	*If this risk occurs:* • Replace main bearing • Overall project contingency is $164M. The project contingency will be drawn down to fund costs associated with this risk. • Adjustments to Target Cost and Contract Schedule are identified in Appendix 5.3C – Major Risk Table of the ADBA *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight
ID #2	**CLOSED** **Main conveyor failure** Due to: Risk ID #6.38 - Main conveyor failure *Assumptions:* • Risk expires at the end of tunnel mining (scheduled for April 2011) • Extensive damage to conveyor belt requiring replacement in excess of 1km	• Metal detection, contingency planning, keep critical spare parts and belts on site • Video monitoring cameras to conveyor belt in particular at transfer points • Increased visual monitoring • Proper TBM operation • Qualified supervisors and maintenance crew • Conveyor structural (rollers) inspection *Assumptions:*						*Monitoring mitigation:* • OPG and OR observing conveyor belt monitoring *Monitoring the risk:* • **[tbd]** *Performance metrics/ early warning signals:* • Signs of bigger blocks of rock on conveyor as seen by visual monitors *Assumptions:* • **[tbd]**	*If this risk occurs:* • Replace conveyor belt • Overall project contingency is $164M .Project contingency will be drawn down to fund costs associated with this risk. • Adjustments to Target Cost and Contract Schedule are identified in Appendix 5.3C – Major Risk Table of the ADBA • For calculation of schedule impact, actual delays will be prorated on the basis that damage to 10km of conveyor belt will result in a 30 day schedule delay *Assumptions:* • Belt readily available to install	**Risk Owner**: Strabag / OPG Oversight
ID #3	**Inundation of tunnel** Inundation of tunnel after TBM breakthrough due to breach of temporary structure at intake works (cofferdam) Consequences: Damage to tunnel, damage to and/or loss of equipment, delay in construction,	• Cofferdam designed for 50 year return • Valve that allows watering up is locked out • 300m grout tunnel has been excavated • Adequate design (checked by Contractor and reviewed by OR) • Close contact and cooperation with INCW operators • Monitoring system implemented and reviewed by designer • Regular inspections by Engineer • Maintenance plan for extended life • Adequate pumping capacity	PROBABILITY	FINANCIAL IMPACT	SCHEDULE IMPACT	MANAGEABILITY	IMMINENCE	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
	and personnel injuries and/or fatalities *Assumptions:* • Risk expires when gates at tunnel intake are in place	• Remediation: Dewater, restore all equipment, and repair/replace cofferdam cells *Assumptions:* •	• ***OPG 2009 Quantitative analysis*** *Probability – 0.02* *Financial Impact – 1 – 5 -20 ($M)* *Schedule delay – 180 – 275 – 365 (days)* • *Assumptions:* *Worst case: everything floods. Flood TBM, Invert carrier, and Arch carrier. 8 weeks to repair cofferdam, 4 months to dewater (need to procure pumps and deliver).* *P5 – Everything survived.* *P95 – Replace concrete and repair damaged carriers. Assume no loss of life.* *Financial impact does not include labour.* *Assume minimal cost to repair cofferdam.* *P5 – Insurance covers equipment and materials repair.*			
ID #4	**Critical marine work impeded by marine operational constraints at the INCW** Critical marine work (cofferdam removal) prevented by operational constraints (i.e. ice conditions) at the INCW Consequences: Delay in construction *Assumptions:* • Operational constraints defined in ADBA - Appendix 1.1 (sss) - Summary of Work – Section 3 (Constraints) • Risk expires when intake cofferdam is removed	• Plan the cofferdam removal work to minimize the amount of marine activity required • Plan cofferdam removal to avoid ice season (December 15 – April 30) *Assumptions:* •	PROBABILITY | FINANCIAL IMPACT | SCHEDULE IMPACT | MANAGEABILITY | IMMINENCE • ***OPG 2009 Quantitative analysis*** *Probability – 0.5* *Financial Impact – none* *Schedule delay – 30 – 60 – 90 (days)* • *Assumptions:* *Worst case: cofferdam removal occurs during winter months.* *Cofferdam removal is currently scheduled during winter 2013.*	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner:** Strabag / OPG Oversight **SME:** K. Child
ID #5	**Tunnel collapse** Tunnel collapse due to inadequate design or construction or ground conditions Consequences: Damage to tunnel, damage to and/or loss of equipment, delay in construction, and personnel injuries and/or	• Extensive geotechnical investigations • Adequate design/construction QA/QC plan • Independent design reviews by Contractor and OR • Geotechnical presence on site (full time) • On-site full time presence by tunnel designer • Design/adjustments as required during construction • Tunnel instrumentation and monitoring of rock support • Material testing (rock dowels, shotcrete) • Convergence monitoring and regular review of results by geotechnical engineer, construction manager and designer	PROBABILITY | FINANCIAL IMPACT | SCHEDULE IMPACT | MANAGEABILITY | IMMINENCE	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner:** Strabag / OPG Oversight **SME:** P.Moorhouse

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
	fatalities *Assumptions:* • Risk expires when tunnel construction is complete	• Establishment of trigger levels for maximum allowed deformation • Emergency rescue and evacuation plan in place • Contact grouting and interface grouting close all voids on both sides of the membrane • Fully testable membrane • Detailed monitoring of liner convergence during pre-stressing • Test/ trials planned for contact and pre-stress grouting • Insurance in place (Transfer Risk to Insurance) • Remediation: Repair and restore tunnel *Assumptions:* •	• ***OPG 2009 Quantitative analysis*** *Probability – 0.05* *Financial Impact – 1 – 2 -10 ($M)* *Schedule delay – 30 – 90 – 180 (days)* • *Assumptions:* *Localized collapse of tunnel (of 10 – 20m) that damages major equipment (i.e. TBM, Invert carrier, conveyor, ventilation, etc.)* *Insurable event with $1M deductible.* *Worst case: collapse of temporary liner since permanent liner collapse would lead to more localized collapse.* *P5 is more localized damage. Insurance deductible for P5.*			
ID #7	**Delays in providing outage for rock plug removal** Contractor delayed in removing the outlet rock plug due to OPG's inability to provide a Pump Generating Station (PGS) outage when required Consequences: Delay in construction *Assumptions:* • According to schedule risk starts April 2013 and expires June 2013 (water-up procedure)	• Early engagement of Independent Electricity System Operator (IESO) to understand consequence of rock plug outage and improve chance of getting outage when it is needed. • Communicate request for flexibility to IESO • Communicate outage changes to IESO as soon as possible, especially once in the 18 month Outage Reference Planning window • The Niagara Plant Group Planning Office scheduled the PGS (PG1- PG6) outage for Monday, June 3 to Sunday, June 16. This date was included in the data used for the Niagara Plant Group Business Plan 2010-2014. *Assumptions:* • Beck complex typically supplies automatic generation control (AGC) for IESO	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE • ***OPG 2009 Quantitative analysis*** *Probability – 0.5* *Financial Impact – none* *Schedule delay – 5 – 10 – 30 (days)* • *Assumptions:* *Source of delay comes from IESO. Note: IESO needs 18 months' notice and NTP can only provide approximately 6 months' notice of when they think the rock plug removal would be required. Spring or fall might be easier to get an outage from IESO since there could be less demand; however system status could be a factor (e.g. nuclear station vacuum building outage).* *Assume a bonus of $200k per day for Contractor.*	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner**: OPG **SME**: Rick Everdell
ID #9	**Prototype overbreak infill operation prolongs schedule** Profile restoration progress delayed due to prototype operation for restoration equipment and initial set up delays (i.e. procurement and delivery of equipment) Consequences: Delay in	• Planned learning curve via slow initial progress rate • Properly designed system • Detailed work preparation and scheduling • Remediation: Timely modifications to improve the efficiency of the infill operation. The contractor is performing work at other "fronts" for profile restoration activity. This will be achieved by using a mobile equipment to install rock anchors, wire mesh, ribs and shotcrete and to complete consolidation grouting. This work is taking place in the areas of the most extensive overbreak.	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
	construction *Assumptions:* • Risk starts September 2009 and expires at completion of profile restoration	*Assumptions:* •	• ***OPG 2009 Quantitative analysis*** *Probability – 0.25* *Financial Impact – none* *Schedule delay – 10 – 20 – 30 (days)* • *Assumptions:* *Critical path. Scheduled advance rate is based on expected average shotcrete delivery and discharge rate (i.e. site shotcrete limitations). 3 month float in schedule. 3 km length for infill operation.* • *Comments: Some correlation with concurrent activities could cause double counting. 7 months until it becomes critical path. 3 months float at end (i.e. conditioning work, not infill activities). In worst case, then 2 months impact on critical path Delivery and procurement could be 2 months delay. Delay in critical path due to late delivery of carrier (delays start date).*			
ID #10	**Concurrent activities delay progress** Overall progress delayed due the logistics of concurrent construction operations (i.e. TBM mining, Invert concrete, Profile restoration, Arch concrete and Grouting) Consequences: Delay in construction *Assumptions:* • Risk decreases in April 2011 when TBM mining complete	• Proper planning of logistics in the tunnel • Adequate passing bays in the tunnel • Traffic controller at tunnel outlet portal • Regular bus service implemented • Ensure TBM mining in on schedule • Remediation: Installation and operation of concrete drop shafts from the surface to reduce the number of concrete truck trips required in the tunnel. Concrete drop shafts installed at 1400, 3369 and 5319m locations. An additional concrete drop shaft is planned for a location at 8000m. *Assumptions:* •	PROBABILITY (red) / FINANCIAL IMPACT (yellow) / SCHEDULE IMPACT (yellow) / MANAGEABILITY (yellow) / IMMINENCE (red) • ***OPG 2009 Quantitative analysis*** *Probability – 0.2* *Financial Impact – none* *Schedule delay – 1 – 90 – 180 (days)* • *Assumptions:* *Worst case: shutdown of arch lining activities because of too many concurrent activities. Assume that it does not occur at the end.* • *Comment: Short window where TBM and Profile restoration activities occur concurrently. Impact of TBM mining rate affects this risk.*	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
ID #11	**Non-conformance and/or non-compliance is identified and requires rework** Permanent works defective or do not conform/comply with specifications due to construction quality (includes permanent works concrete deficiencies) Consequences: Cost and delay in construction related to rework *Assumptions:* • Risk starts when tunnel final lining commences and ends when pre-stressing is complete	• Full-time OR presence during construction • Structured submittal and design review process by OR and Strabag • Monitoring construction works against plan (OR and Strabag) • OR regularly reviews Contractor's formal non-compliance process in QC reports • Contractor required to have a full time Quality Assurance manager according to ADBA • OPG/OR gives Contractor Disallowance Advisory notices to notify Contractor that all costs arising from future occurrences of specific actions, omissions or occurrences would be disallowed costs *Assumptions:* •	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE • ***OPG 2009 Quantitative analysis*** *Probability – 0.5* *Financial Impact – 3 – 4.5 – 6 ($M)* *Schedule delay – none* • *Assumptions:* *Worst case: re-pouring of concrete, tearing out localized areas of concrete lining and membrane (i.e. aggregate of 25m) because of sub-standard concrete/thickness, etc. Concrete placement at $40,000 per m and removal $20,000 per m. Assumes all non-conformances/non-compliances are detected. Quality concerns discovered during operation are outside the scope of this analysis. Assume no schedule delay so no burn rate.* • *Comment: Adjust target if structure is removed and no problem is found.*	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child
ID #12	**Contract management problems increases project costs** Project costs increase due to contract management problems (including claims and oversight of Contractor) Consequences: Cost increase *Assumptions:* • Risk expires one year after project completion (1 year limitation on claims)	• Use of detailed project procedures • OPG conducting intermittent audits (e.g. Cost Control Audits) • Contractor's books of accounts and financial statements under the ADBA are fully open to OPG • Well defined contract language around disallowed costs. Adequate contract language to clearly define Contractor's obligations. • Adequate and proactive Owner oversight. *Assumptions:* •	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE • ***OPG 2009 Quantitative analysis*** *Probability – 0.3* *Financial Impact – 5 – 10 – 20 ($M)* *Schedule delay – none* • *Assumptions:* *Worst Case: unexpected ground conditions (e.g. sidewalls spalling effecting gripper efficiency). Frequency and magnitude of occurrence captured in P95. Assume no schedule delay so no burn rate. Target date extended due to claims.*	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. • *Assumptions:* •	**Risk Owner:** OPG **SME:** Rick Everdell

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ID	Risk	Mitigation Detail	Residual Risk					Quantitative Analysis	Notes	Risk Owner & SME
			PROBABILITY	FINANCIAL IMPACT	SCHEDULE IMPACT	MANAGEABILITY	IMMINENCE			
ID #18	**Contractor defaults on its obligations** Contractor abandons project due to potential for significant loss Consequences: Cost and delay in construction - to be addressed through a superseding business case. *Assumptions:* • Risk expires at project completion	• Incentives (Interim Completion Fee - payable at TBM Completion Date and Substantial Completion Fee) for Contractor to complete the project are included in ADBA • Contractor to remain interest-neutral under ADBA • Cost reimbursable contract with cost and schedule performance incentives • OPG has accepted risk for specific base-lined events • Remediation: Project would be re-evaluated and addressed through a superseding release of funds. Strabag provided a Letter of Credit (LOC) and parental indemnities. OPG to pursue legal options under ADBA. *Assumptions:* •						*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • Project would be re-evaluated and addressed through a superseding release of funds. *Assumptions:* •	**Risk Owner**: OPG **SME**: Rick Everdell
			•							
ID #19	**Excessive convergence delays installation of final lining** Ground convergence exceeding specifications delays installation of the final concrete lining due to ground conditions and/or inadequate support *Assumptions:* •	• Initial support design allows deformation • Clearly defined support for the whole range of ground conditions • Materials testing and convergence monitoring • Full-time geotechnical engineer on site • Additional rock support available • Review of tunnel convergence prior to installation of final liner • Final liner installed some time after tunnel excavation • Remediation: Delay final lining progress until convergence within specification. Perform remedial work to restore initial and final tunnel lining. *Assumptions:* •						*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: P. Moorhouse
			•							
ID #20	**Fire damages tunnel, equipment, and materials** Fire in the tunnel due to hot works, faulty equipment, overheating equipment, flammable gases and liquids and open flames and smoking Consequences: Damage to tunnel, damage to and/or loss of equipment, delay in construction, and personnel injuries and/or fatalities *Assumptions:* • Risk expires when tunnel construction is complete	• Emergency response and evacuation plan in place • Emergency rescue containers and Emergency Breathing Apparatus (EBAs) available for personnel on all major equipment • Adequate hazard identification and job safety plans • Adequate equipment design • Regular monitoring during construction • TBM power pack designed with deluge system • Hot works permits • Adequate fire lines and extinguishers on identified potential fire hazards • Fire retardant conveyor belt and cables • Minimize storage of material in the tunnel • Transfer risk to Insurance • Remediation: Make an insurance claim, if applicable *Assumptions:* •						*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child
			•							

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
ID #23	**Significant environmental incident during Owner Only Project** Major environmental regulatory infraction due to a reportable spill or discharge that results in a charge under federal or provincial legislation and associated regulations or under a municipal by-law. Consequences: Regulatory orders and charges, third party actions, and reputational damage *Assumptions:* • Risk expires when tunnel construction is complete	• Transferred to Strabag via Amended Design Build Agreement (ADBA) OPG is Owner Only. Contractor is required to comply with all applicable statutory and regulatory requirements relating to discharges to the environment • ADBA requires Strabag to comply with applicable laws and the Environmental Management Plan • ADBA specifies Contractor's environmental reporting requirements. The Contractor is responsible for reporting its discharges to the regulator, as required and to OPG • OPG and OR reviewing Strabag environmental reports and audits • Residual risk includes impact to OPG's corporate reputation *Assumptions:* •	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE •	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: C. Mee
ID #24	**Significant safety incident during Owner Only Project** Major safety incident due to construction related accident or work stoppage Consequences: Regulatory orders and charges, personnel injuries and/or fatalities, and reputational damage *Assumptions:* • Risk expires when tunnel construction is complete	• Transferred to Strabag via Amended Design Build Agreement (ADBA). OPG is Owner Only • Amended Design Build Agreement requires Strabag to comply with applicable laws and implement the Project Specific Site Safety, Security, Public Safety and Emergency Response Plan • Design Build Agreement specifies Strabag's safety reporting requirements • Design Build Agreement requires Strabag to maintain workers' compensation coverage • OR issues Safety observations • OPG and OR monitoring of safety reports • Residual risk includes impact to OPG's corporate reputation *Assumptions:* •	PROBABILITY / FINANCIAL IMPACT / SCHEDULE IMPACT / MANAGEABILITY / IMMINENCE •	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag **SME**: K. Child

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ID	Risk	Mitigation Detail	Residual Risk	Quantitative Analysis	Notes	Risk Owner & SME
ID #38	**Fall of ground incident** Fall of ground due to inadequate design and/or construction of ground support and inadequate monitoring of convergence and support condition Consequences: Damage to tunnel, damage to and/or loss of equipment, delay in construction, cost increase, and personnel injuries and/or fatalities *Assumptions:* •	• Knowledge gained from fall of ground event at 3+610 • Clearly defined monitoring protocol • Monitoring of ground movement by designer • Full time geotechnical engineer and designer on site • Detailed analysis and review of monitoring results • Tunnel instrumentation and monitoring of rock support • Mobile equipment with sufficient reach available on site for installation of additional rock support • Remediation: Perform remedial work to restore initial tunnel lining • *Assumptions:* •	PROBABILITY | FINANCIAL IMPACT | SCHEDULE IMPACT | MANAGEABILITY | IMMINENCE •	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: P. Moorhouse
ID #39	**Failure in arch concrete system causes interruption to operations** Arch concrete progress delayed due initial set up delays and equipment failures during on-going operation Consequences: Cost and delay in construction *Assumptions:* •	• Training of personnel, adequate supervision and regular preventative maintenance • Typical tunnel formwork system • Critical spare parts on site • Contingencies for all critical equipment in place *Assumptions:* •	PROBABILITY | FINANCIAL IMPACT | SCHEDULE IMPACT | MANAGEABILITY | IMMINENCE •	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child
ID #40	**Pre-stress grouting prolongs schedule** Pre-stress grouting progress delayed due to initial set up delays and scale of operation Consequences: Cost and delay in construction *Assumptions:* •	• Extensive design and input from grouter • Discussions with third-party designers and owners that have used this technique • OR review of design • OR monitoring of construction • Trial sections of tunnel to finalize application of method *Assumptions:* •	PROBABILITY | FINANCIAL IMPACT | SCHEDULE IMPACT | MANAGEABILITY | IMMINENCE •	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child

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ID	Risk	Mitigation Detail	Residual Risk					Quantitative Analysis	Notes	Risk Owner & SME
			PROBABILITY	FINANCIAL IMPACT	SCHEDULE IMPACT	MANAGEABILITY	IMMINENCE			
ID #41	**Swelling in the invert** Swelling of ground in the tunnel invert at the low point due to exposure to water Consequences: Cost in construction rework *Assumptions:* •	• Project Disallowance Advisory No. 005 issued to Contractor • Disallowance Advisory identifies actions that OPG expects the Contractor to perform to control water below the invert concrete lining at the tunnel low point • OPG retained a geotechnical expert to provide engineering services to investigate, assess, determine remedial measures if required and report on the potential of swelling within the Queenston Formation beneath the already installed invert *Assumptions:* •	(yellow) •	(yellow)	(yellow)	(yellow)	(yellow)	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME: P. Moorhouse**
ID #42	**Loss of key project personnel** Loss of key project personnel due to length of project Consequences: Cost and delay in construction *Assumptions:* •	• Amended Design Build Agreement identifies the key personnel in the Contractor's organization and the requirements for the replacement of key personnel *Assumptions:*	(red) •	(green)	(green)	(yellow)	(red)	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME: H. Charalambu**
ID #44	**Concrete delivery problems delay progress of final lining** Concrete delivery problems delay progress of final lining due to the lack of a reliable off-site concrete supply that meets required specifications Consequences: Cost and delay in construction *Assumptions:* •	• Dedicate the Dufferin Concrete Niagara Falls plant to supply the project and move regular local concrete production to the Welland plant • Niagara Falls plant to meet the delivery and quality requirements • Remediation: Install a second concrete production plant on-site to meet the delivery requirements *Assumptions:*	(red) •	(yellow)	(red)	(yellow)	(red)	*Probability:* • *Financial Impact ($):* • *Schedule Impact (days):* •	*Comments:* • *Assumptions:* •	**Risk Owner**: Strabag / OPG Oversight **SME**: K. Child

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Risk Attributes

Probability *(the probability that a risk will occur)*	1 (Low)	Low probability (< 10%)
	2 (Medium)	Medium probability
	3 (High)	High probability (> 70 %)

Financial Impact *(the financial consequences of a risk should it occur)*	1 (Low)	The risk will have negligible financial impact on the Project (e.g. “risk is easily absorbed by the Project budget”)
	2 (Medium)	The risk will have a notable financial impact on the Project (e.g. “additional funds would be required by the Project”)
	3 (High)	The risk endangers the financial viability of the Project (e.g. “significant impact on the Project business plan”)

Schedule Impact *(the impact that a risk would have on the schedule, and more importantly overall project duration, should it occur)*	1 (Low)	The risk will have little or no Project schedule impact (delay tasks within their available free float)
	2 (Medium)	The risk will have a notable Project schedule impact (delay one or more tasks on the critical path)
	3 (High)	The risk will have a significant impact on the Project schedule (Project in-service date would be delayed)

Manageability *(the degree to which the Project is able to control the risk)*	1 (Low)	The Project will have no difficulty controlling or influencing the outcome of the risk (e.g. “risk easily handled by the Project’s managed system”)
	2 (Medium)	The Project will have some difficulty controlling or influencing the outcome of the risk
	3 (High)	The Project will be unable to control or influence the outcome of the risk (e.g. “no change to the risk regardless of what the Project does”)

Imminence *(the nearness in time at which the risk is expected or predicted to occur.)*	1 (Low)	The risk is expected or predicted to occur in the long term (after 18 months)
	2 (Medium)	The risk is expected or predicted to occur within the medium term (between the next 6 to 18 months)
	3 (High)	The risk is expected or predicted to occur within the short term (within next 6 months)

Appendix D – Lessons Learned

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
1	**Schedule**	Time-way (linear) schedule.	Success - Excellent tracking and communication tool for a linear project.	Allowed the Project team, stakeholders, and sponsor to understand both progress and performance.	Although OPG carries out a limited number of linear projects, it could consider employing this format on other types of projects. Project team should document the Time-Way Scheduling process and any lessons learned to share with other project teams.	None.
2	**Cost**	BCS cost broken out by month in a defined work breakdown structure.	Success - Able to monitor against the baseline.	More accurate tracking/forecasting.	Projects should have a detailed cost broken out by month in advance of project release.	None.
3	**Cost**	Forecasting model.	Success - Development of a detailed forecasting model.	Ability to forecast final completion cost quickly after month end.	Projects should have a forecasting model developed in order to forecast final costs based on current month actuals.	None.
4	**Scope**	Disposal of surplus goods.	Problem - Unclear language in the ADBA with respect to: 1) Owner/Contractor roles in the Disposal of Surplus Goods Process, and	Inefficient use of resources (OPG, Owner's Rep, & Contractor) with numerous revisions of plans required.	Clear contract language that identifies OPG's expectations to optimize the net value recovered. Use of an unreserved auction was effective for a project of this size.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
			2) Method of disposal.			
5	**Scope**	Identification of Plant Group wants/needs.	Problem - It was difficult for the Plant Group to identify all of their requirements from the concept drawings	Uncertainty about the end product (i.e. intake fencing, parking lot, fall arrest, etc.).	Involve appropriate stakeholders early in the project. The Plant Group needs to be provided sufficient time and resources to document what they want and the rationale. Dedicated resources should be considered.	None.
6	**Quality**	Owner requirements/ expectations and inadequate division of responsibilities.	Problem - Owner has limited input on Contractor's resource allocation to: QA, QC, Health & Safety, and Environment (i.e. production employees were responsible for quality control).	Owner requirements/ expectations in these areas not met. Production overrides quality - conflict of Contractor's priorities. Quality control was impacted.	Design-Build contracts should contain Owner's requirement for Contractor site positions, numbers, disciplines, and qualifications. If quality control is to be properly enforced by the contractor, a clear division/separation of the role must be made. Having production employees responsible for quality typically does not work. Independent management (i.e. 3rd party) of Quality is a	Further assessment of OPG contracting model/terms - emphasize inclusion of project-specific and/or OPG standards in the areas of safety, environment, & quality (SEQ).

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
					better (recommended) approach for priority management.	
7	**Quality**	Issue management.	Problem - Reactive approach taken by Contractor to resolve technical/construction issues. Root cause analysis not performed by Contractor.	Cost and schedule impact.	In tunneling, the premise to battle through existing situations/conditions is the norm. Fixing a problem when it is encountered should be given greater consideration (i.e. over break, excessive construction water). Also, proceeding with work that does not have a submittal or has a submittal without an ‘acceptable status’ should not occur (i.e. overbreak restoration).	A more robust contingency planning process (by the contractor) to incorporate root cause techniques to support problem resolution of construction/technical issues.
8	**Quality**	Method Statements.	Problem - Contractor did not utilize method statements effectively.	Education by OR required.	Method Statements are an effective tool if taken seriously and prepared with the intent of being utilized and not just to satisfy a Project/Contract requirement.	Provide Method Statement templates/examples that clearly outline expectations of Contractor.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
9	**Human Resources**	Consistent staffing.	Problem - There were significant staff changes in the Plant Group engineering and management ranks as a result of the long duration of the project.	No real buy-in/alignment from Plant Group staff to review/comment on any drawings circulated.	No recommendation - it is difficult to allocate OPG production and engineering staff on a project for 8 years.	None.
10	**Human Resources**	Team building.	Success - A team-building event held at the beginning of the project allowed all parties (Contractor & key subcontractors, OPG, OR) to get to know each other on a personal basis.	This opened the lines of communication and assisted in building trust between parties which allowed resolutions to be achieved on a shorter timeline.	Whether it is an organized team building event or simply a summer barbecue, these events should be held on a regular basis throughout the life of the project.	None.
11	**Human Resources**	Dedicated core project team.	Success - core OPG/OR project team remained dedicated to the Project.	Consistency and limited knowledge transfer loss.	Start out with key players and bring on people as needed.	None.
12	**Communications**	Use of tables and bullets in the monthly report.	Success - Although making the monthly report somewhat longer, the use of table and bullet formatting in various sections of the report made the detail contained in the monthly report more visible and comprehensive.	Improved communications.	Share NTP monthly report template with the HTO PMO to make it available for other projects.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
13	**Communications**	Community Impact Agreement (CIA) & Liaison Committee.	Success - Forecast impacts of the Project on the host communities were proactively addressed.	Compensation payments permitted host municipalities to address significant local concerns in advance and the Liaison Committee promoted ongoing dialogue to limit community issues throughout Project execution.	Adopt similar agreements & procedures with host communities where warranted by project scale & potential community impacts.	None.
14	**Communications**	Communication management.	Problem - Information was not consistently being cascaded to the site-level. Miscommunication with external stakeholders.	OPG reputation. Project cost and schedule.	Ensuring the most recent/accurate information is available to those that require it. Too often information is not shared and by the time it reaches the level where it is required it is either too late or inaccurate. Sharing information is a key to success.	Incorporate Contractor into overall project communication matrix. Contractor discipline / management system issue.
15	**Communications**	Partnering approach / teamwork.	Success - All parties eventually 'bought into' the partnering concept even though the Contractor was very silo'd (internally).	Effective teamwork and cooperation by external stakeholders.	If a partnering concept is established early in the project, it can be extremely effective. Effective partnering requires 'give-and-take' on both sides. Having divided sectors which may have individual	OPG's code of conduct and expense policies may restrict team building opportunities with external contractors and forego the benefits.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
					needs that are put above completion as a whole are harmful and not in the spirit of partnering. Recognizing/considering the thoughts/ideas of others is a part of this.	
16	**Risk**	Comprehensive risk review meetings.	Success - The diverse attendance of key project management and construction staff allowed for productive risk review meetings (monthly reviews and analysis meetings).	Proactive risk management with risk definition and risk response actions evolving over the life of the project.	Commercial terms and conditions with installation contractors, design contractors, and owner's engineer should stipulate involvement of all parties in co-operative risk management activities.	Emphasize 'shared' risk register approach.
17	**Risk**	Combined risk management process was required by underwriters of the Builders All-Risk Insurance.	Success - It promoted collaboration between the contractor, owner, & owner's rep in the identification and management of the majority of the significant Project risks.	Strong communication amongst all parties concerning design & construction risks ensuring clear understanding of risks, appropriate mitigation, & clear establishment of accountabilities.	Where warranted by project scale & risks, adopt combined risk management process ensuring owner / contractor collaboration on risk management during execution of future OPG projects.	Share this practice with other HTO PMO Clients at a future quarterly PMC meeting.
18	**Risk**	Format of the risk registers.	Problem - Original risk registers were populated in Excel format. Became cumbersome to review.	Less efficient meetings.	Populate risk registers in a database format to allow for easier sorting / review of risks and tracking of changes.	Look at using established commercial software for this on future projects.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
19	**Risk**	Attempt to transfer risk through fixed price.	Problem - Design-build lump-sum contract model gives the Owner the expectation of risk acceptance by the Contractor even though the risk has not been adequately assessed or priced. Risks that are not identified and allocated become disputes.	Project may not have had sufficient overall cost allocation (contingency) to cover risks. False sense of security in reporting to corporate oversight.	Risk assessment must start before the contract stage, be thorough and documented. Allocation of risk must be addressed in the contract.	None.
20	**Procurement**	Contracting strategy - Fixed-price contract inappropriate for projects with significant site-specific underground or geotechnical risks.	Problem - Significant geotechnical risk that Design-Build contractor never accepted. Conditions were more adverse than the baseline which resulted in claims / disputes. Contractor cannot absorb significant losses (without potential for recovery on future work).	Increased costs and schedule delays due to significant work/time to: (i) resolve disputes, and (ii) renegotiate the contract.	Forego fixed price where geotechnical risks are high and match contracting strategy to risk profile. Use target cost approach with incentives/disincentives to optimize risk transfer to contractors.	Consider utilization of the CII PDCS tool.
21	**Procurement**	Contract renegotiation.	Success - Renegotiated Target Price Contract was accurate with no cost or schedule overruns over a period of four years.	There was a shared ownership of cost and schedule and more awareness of Owner's risk.	Better model for underground works than fixed price.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
22	**Integration**	Owner's Rep. and OPG (Project Management and Law) co-ordination of Project changes and risk management.	Success - Very successful integration of Owner's Rep. and OPG (Project Management and Law) efforts related to the drafting, review, and signoff of PCD's.	Well-defined roles resulted in effective management of Project risks and changes - best practices in team integration employed.	Project management teams employing external Owner's Rep.'s should reference NTP - reflects an excellent use of personnel and resources and effective time management as well as risk mitigation practices. Best practices employed with very successful results.	None.
23	**Technical / Design**	Original contract did not require full-time design representative at site. Requirement added when Amended Design-Build Agreement (ADBA) was negotiated.	Problem - Initial problems with construction QC and interpretation of design when design rep. was not on site.	QC and engineering issues leading to delay and rework (cost and schedule impact).	When using the Design-Build project delivery model, the Contractor should be required to have a design representative on site full-time during construction.	None.
24	**Technical / Design**	Lack of technical and procurement expertise allocated to the Project by the Design-Build contractor.	Problem - Design-Build contractors tend to focus resources on the areas of the work where the company has expertise (i.e. contractor focus on tunnelling to the	Lack of management and coordination of subcontracts leads to cost over-runs, quality issues and schedule over-runs.	Design-Build contracts should contain Owner's requirement for site positions, numbers, disciplines, and qualifications.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
			detriment of structures, gates, mechanical equipment, etc.).			
25	**Technical / Design**	Resolution of problems.	Success - Major problems were overcome by OPG, the Owner's Rep., and the Contractor working together harmoniously and pragmatically	Timely resolution of problems.	In part this was made possible by scoring and choosing the correct Contractor during proposal evaluations.	None.
26	**Business Processes**	Signing authorities for contract changes - same level of signing authority for changes as in the original contract.	Problem - Difficult to obtain executive level signatures. Numerous change orders over life of contract and some were of insignificant value or had no impact on cost or schedule envelopes.	Slows down the change management process; requires unnecessary legal input because of 'high level signature'.	Reconsider OPG OAR policy given success with revised DBA precedent that permits flexible contract administration - low cost (under $100K) and no schedule changes within approved cost and schedule envelopes do not require signing by EVP levels; set-up specific project authorities tailored to the project.	Include detailed descriptions on PCD's.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
27	**Project Controls**	Inadequate inventory management by the Contractor.	Problem - Difficulty in substantiating the value of goods in inventory at the time of contract conversion to target-price and substantiating the value of surplus goods at disposition (i.e. scrap/write-off, transfer or sale).	Reputational risk for OPG concerning inadequate controls, risk of inability to recover unsubstantiated Project costs, etc.	Ensure that future contracts stipulate OPG expectations on robust inventory management to facilitate substantiation of procurement activities and control of OPG-owned project assets.	OPG also needs to have proper project controls infrastructure in-place to support target-price contracts.
28	**Project Controls**	Inconsistent use of cost, schedule, and resource tracking tools.	Problem - True schedule position not well understood by all stakeholders. Each stakeholder had difficulty in assessing true cost, schedule, and resource position.	Ineffective resource allocation. Schedule and cost impact.	Decide on standard tools (project-specific) early in the process and allocate resources to ensure consistency and compliance with standards. Utilize simple forms (i.e. inspection, audit, or summary forms) to accurately capture and report on daily progress.	Common scheduling approach required - contractor tracked progress outside of P3 and had to report using P3.
29	**Project Controls**	Subcontractor management.	Problem - Subcontract submissions and claims were a straight pass through by the Contractor without any review.	Negotiations more difficult and time consuming. No language in Contract to force the Contractor to review for reasonableness.	More of a relationship issue - Emphasize requirement for a subcontractor management plan and OPG expectations. There are limited opportunities to update our contract T&C's.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
30	**Project Controls**	Dispute Resolution processes - OPG's use of a DRB composed of 'professional arbiters'.	Problem - Original DRB process did not result in a streamlined, satisfactory resolution of the major overbreak claim. In particular, usual protections of legal proceedings (like arbitration or litigation) were not available resulting in significant risk to OPG.	A decision that required a "compromise" and ultimately a renegotiation of the DBA. Significant additional legal costs and management time expended in a process with an 'unknown' outcome.	Limit use of DRB's in DB agreements (possibly to technical issues only). Before any 'new' process is used or considered for use as a dispute process, ensure it has been practically evaluated in (a) OPG, or (b) industry. Where speed of resolution outweighs risk of a finding against OPG, consider more informal resolution processes (such as an advisory committee of executives or technical panels of experts) and write the process into the agreement. Arbitration and litigation for significant issues remains the preferred approach.	None.
31	**Health and Safety**	Owner-Only execution.	Success - The Owner's Rep. and Plant Group did a very good job separating Strabag's work from the Plant Group's work.	Minimal risk of OPG assuming Constructor role for the entire project.	Requirement to establish clear, consistent boundaries between the contractor and OPG.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
32	**Environment**	EA commitments (made several years prior) constrained opportunities during detailed design & construction.	Problem - Limited creativity on design and construction that prevents incorporation of Contractor experience and innovations that could reduce Project cost and shorten the duration of the project.	Prevented potential cost & schedule savings such as tunnel alignment through St. Davids Gorge (above problematic Queenston shale), multiple workfaces, excavation methods, construction logistics, etc.	Throughout the EA process on future OPG projects, retain as much flexibility as possible to accommodate subsequent (contractor) experience & innovations during detailed design & construction.	None.
33	**Environment**	Environmental Management Plan	Problem - Although this was a comprehensive document and a very good planning tool, it needed updating as the Project proceeded into construction. Tendency was for the document to be more theoretical than practical. Also, the actual Contractor environmental staff numbers were much less than initially defined.	Increased regulatory compliance risks.	Insufficient resources - Probably one manager and 2 assistants would have been the appropriate level of environmental staffing, especially in the initial stages. The use of third party consultants, rather than on site specialists, proved to be the manner of addressing many of the technical issues (e.g. water treatment, storm water management plan).	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
34	**Environment**	Water treatment requirements.	Problem - Plant as initially sized was too small for the amount of water and sediment to be processed. Specifically, the sediment/total solids loading was considerably more than anticipated. The first retention pond was poorly designed/constructed.	Sedimentation plans had to be developed and then amended as the Project proceeded. Also, process water had to be discharged at the Intake, after the FOG, this water should have been treated in the same manner as that being discharged at the Outlet or the piping system within the tunnel should have been restored much more quickly to route the water back to the Outlet.	The addition of the more robust sedimentation pond upstream of the initial pond with the cells operating on a rotating basis greatly alleviated the problem. Use of the sediment, combined with organic matter, proved to be a useful material for site restoration/revegetation.	None.
35	**Stakeholder Management**	EPSCA Labour Relations	Success - Contractor used a single union (labourers) employed under the EPSCA agreement.	EPSCA prevents major strikes (however does not stop inter-union squabbles over jurisdiction).	Note: This approach required the Contractor to resolve disputes at the labour board and may have prevented expertise from other skilled trades. This is a project-specific LR approach.	None.

ID	Category	Issue	Problem/Success	Impact	Recommendation	Additional OPG Comments/Actions
36	**Stakeholder Management**	Relationship with Regulatory Agencies	Success - Good Relationship with Regulatory Agencies. Upfront consultation and ongoing meetings with key agencies (e.g. MOE, DFO, MNR) and local municipalities – greatly assisted.	Issues could normally be directly addressed.	Upfront consultations and meetings with Regulatory Agencies. Development of working relationships.	None.
37	**Records Management**	Project mandated to use OPG's SCI system.	Problem - No explanation/description provided for each SCI number which left room for misinterpretation in numbering/filing of documents, drawings, correspondence, etc.	Many submittals/documents have been given the wrong SCI number; NPG will need to cross-reference to correct the SCI number.	Provide detailed descriptions and examples for each SCI number mandated to be used on a project managed by an outside consultant.	None.
38	**Records Management**	Project database.	Problem - Multiple databases were used to track Project information.	Provided ability to locate various information quickly. Using multiple databases required double entry at times. The submittal database was secure which limited the flexibility to make required changes.	An all-inclusive database program to track all project information, which provides program flexibility. Note: These types of programs were not very common at the time this project was initiated.	None.

Board Staff Interrogatory #72

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exhs D2-2-7, D2-2-8 and D2-2-10

OPG has provided copies of third party reports in the above referenced exhibits.

a) Please provide a copy of any other third party reports regarding the DRP prepared during the planning phase that have not already been filed by OPG in EB-2016- 0152.

b) Please provide a copy of all audit reports regarding the DRP.

c) Will OPG receive reports from any other third party independent oversight groups involved in the DRP during the execution phase? What is the frequency? Will they generate written reports? Who will receive the reports?

d) What is OPG's Audit program during the execution phase of the DRP? What areas will be audited? What is the schedule for the audits during the execution phase of the DRP? Who will receive the reports?

Response

a) There are an extensive amount of third party reports regarding the Darlington Refurbishment Program (DRP) that cover technical details on a variety of topics. The following is a list of third party oversight reports regarding the DRP:

1) Modus/Burns & McDonnell – Definition Phase

Reports are provided as Attachments as listed:

1. Initial Project Assessment – Darlington Nuclear Refurbishment Project (August 13, 2013)
2. Report to Nuclear Oversight Committee – 4th Quarter 2013
3. Report to Nuclear Oversight Committee – 1st Quarter 2014
4. Report to Nuclear Oversight Committee – 2nd Quarter 2014
5. Report to Nuclear Oversight Committee – 3rd Quarter 2014
6. Report to Nuclear Oversight Committee – 4th Quarter 2014

7. Supplemental Report to Nuclear Oversight Committee Observations Regarding 4d Cost Estimate - 4th Quarter 2014
8. Report to Nuclear Oversight Committee – 1st Quarter 2015
9. Report to Nuclear Oversight Committee – 2nd Quarter 2015
10. Report to Darlington Nuclear Refurbishment Project – 3Q 2015
11. Report to Darlington Review Committee of OPG Board of Directors
12. Nuclear External Oversight Assessment Report Cost Management & Earned Value
13. Nuclear External Oversight Assessment Report Assessment of 4c Estimate and Cost Management
14. Nuclear External Oversight Review of OPG Risk Management Practices and Procedures – February 2015
15. Report to Board of Directors Board Retreat October 1-2, 2015
16. BMcD/Modus Recommendations 2Q 2015 Report to NOC
17. Nuclear External Oversight Assessment of OPG Operating Experience & Lessons Learned Practices and Procedures
18. Nuclear External Oversight Review of Darlington Refurbishment Schedule Management Practices and Procedures
19. Attachment B – Update of BMcD/Modus Recommendations from Initial Project Assessment of August 2013
20. Nuclear External Oversight Assessment Report of DR Team's Process for Developing the RQE Estimate (already filed at Ex. D2-2-8, Attachment 2)
21. Independent Oversight Team – Assessment of OPG Scope Definition and Management Process

2) <u>Previous Ontario Minister of Energy - Independent Advisor</u>

Reports are provided as Attachments as listed:

22. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program - Q3 2014
23. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program - Q4 2014
24. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program - Q1 2015
25. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program - Q2 2015
26. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program - Q3 2015
27. Report to the Minister of Energy on the Oversight of the Darlington Refurbishment Program – Q4 2015

b) OPG produces two types of audit reports that are applicable to the DRP: (1) Nuclear Oversight reports, and, (2) Internal Audit reports:

1) <u>Nuclear Oversight</u>

During the period of January 1, 2014 to September 30, 2016, Nuclear Oversight performed 45 Audits and Assessments (34 Audits, 11 Assessments) that included Darlington Nuclear Refurbishment in scope. Of those, 13 identified issues requiring corrective action within Refurbishment.

Nuclear Oversight works closely with the Line organizations being evaluated, including implementing processes that provide acknowledgement of the issues identified and achieving agreement and ownership of corrective actions.

The issues identified during this period consisted of deficiencies/gaps from a fleet or station perspective as well as specific to the refurbishment project. The areas requiring further corrective action included assessment of planning and design activities, conduct and implementation of plant activities, as well as assessment of programmatic effectiveness.

The following chart contains the list of the Nuclear Oversight Audits and Assessments that included Darlington Nuclear Refurbishment in Scope. All findings and associated management actions relevant to the DRP are provided in Attachment 28.

Chart 1 – Nuclear Oversight Audits

Audit #	Audit Title
2014-005	Work Protection
2014-006	Pressure Boundary Section 18
2014-008	PB Program Review (incl. CAP review surveillance)
2014-011	Procurement Engineering
2014-012	Human Performance
2014-017	Fire Protection Program
2014-018	Environment Programs
2014-020	PB Design Control (including PB Procurement Engineering)
2014-021	PB Control of Processes & Test Control and Material Management
2015-013	Software Program – Real Time Process Computing
2015-014	Environmental Management
2015-016	Fire Protection
2015-018	PB Design Control (incl: PB Procurement Eng. Aspects)
2015-020	Pressure Boundary Audit - Section 18
2015-021	Reactor Safety Program
2015-022	Project Management
2015-024	Items & Services Management, including Pressure Boundary
2015-029	Heavy Water Management

Audit #	Audit Title
2015-033	Configuration Management
2016-001	Health & Safety Management System Program
2016-002	Corrective Action Program
2016-004	Equipment Reliability
2016-005	Major Components
2016-008	Welding
2016-013	Risk and Reliability
2016-014	Environmental Management
2016-015	Conduct of Maintenance
2016-016	Records and Documentation
2016-020	Work Management
2016-021	Work Protection
2016-027	Integrated Aging Management
2016-028	DNR Project Management
2016-029	DNR Conduct of Engineering
2016-031	DNR Emergency Preparedness

Chart 2 – Nuclear Oversight Assessments

Assessment #	Assessment Title
2014-200	Darlington Nuclear Refurbishment (DNR) Engineering Activities
2014-204	Darlington Performance Assessing - Operations & Maintenance Readiness for DNR
2014-310	Contract Administration Assessment
2014-319	Fleet Performance Assessing - CMO 180 Day Follow
2015-202	Darlington Nuclear Refurbishment Chemistry
2015-205	DNR - Engineering
2015-206	DNR Contractor Safety Plan
2015-208	Darlington NLO Initial Training
2015-321	Follow-up to Human Performance Audit NO-2014-012
2016-208	Pressure Boundary Darlington Refurbishment
2016-209	SATM & Housekeeping Darlington Nuclear Generating Station ("DNGS")

2) Internal Audit

During the period of January 1, 2014 to September 30, 2016, Internal Audit performed 17 audits that included DRP in scope.

The issues identified during this period include (but are not limited to) deficiencies with documentation, unclear organizational accountabilities, contractor non-compliances, planning and scheduling issues, and financial controls.

The following table contains the list of the Internal Audit reports relating to DRP. All findings and associated management action plans relevant to the DRP are provided in Attachment 29 (confidential).

Chart 3 – Internal Audit Reports

Audit #	Audit Title
14-15	Administration of Contractual Documentation - Refurbishment
14-17	Finance's Control Over Darlington Refurbishment
14-18	Turbine Generator (TG) Critical Parts Procurement – Darlington Refurbishment Project
14-26	Darlington Station Readiness for Refurbishment
15-17	EPC Contractor Procurement Review – Darlington Nuclear Refurbishment Project
15-24	Invoice Review & Approval Process – DRP Projects
15-47	ES MSA Recovery negotiations Audit - Follow-up on 2013 Auditor General Findings
16-07	Darlington Nuclear Refurbishment Project Management Audit
16-08	Darlington Nuclear Refurbishment – Contractor Invoicing Audit
16-09	Darlington Nuclear Refurbishment On boarding
16-13	Darlington Nuclear Refurbishment Contractor and Subcontractor Management Audit
16-23	Darlington Nuclear Refurbishment– Retube & Feeder Replacement Construction and Tooling Audit
16-24	Darlington Nuclear Refurbishment Turbine Generator Engineering Audit
16-25	Darlington Nuclear Refurbishment Integrated Database for Project Reporting Audit
16-39	DNR Contractor Procurement – R&FR Project Audit

c) External oversight of the DRP is being conducted on behalf of the Board of Directors, the Ontario Minister of Energy, and OPG's President and CEO. This will continue throughout the Execution Phase:

1) Darlington Refurbishment Committee of the OPG Board of Directors- Burns and McDonnell

OPG's Board of Directors recently re-engaged Burns and McDonnell with Modus as subcontractors to provide independent oversight services during the Execution Phase. The Burns and McDonnell reports are submitted to the Darlington Refurbishment Committee of the OPG Board of Directors at their quarterly meetings.

2) Ontario Minister of Energy - Independent Advisor

Please see Ex. L-4.3-1 Staff-222 for description of the Ontario Minister of Energy's oversight during Execution Phase.

3) OPG President and CEO-Refurbishment Construction Review Board (RCRB)

Please see Ex. L-4.3-1 Staff-222 for a description of the RCRB. Reports are provided to OPG's President and CEO.

d) OPG's Audit program during the Execution Phase of the DRP is as follows:

1) <u>Nuclear Oversight</u>

Nuclear Oversight Rolling Audit Schedule Q3 2016 - Q3 2017 (Attachment 30) represents the current Nuclear Oversight Audit plan for the next five quarters. The DRP (see: Darlington Nuclear Refurbishment (DNR) column on the attached) is in scope for the majority of the planned audits. The Nuclear Oversight 2017-2019 Audit Plan is below:

Chart 4 – Nuclear Oversight 2017-2019 Audit Plan

AUDITS	2017	2018	2019
Pressure Boundary	X	X	X
Pressure Relief Valves			X
Conduct of Engineering – Design Authority	X		
Conduct of Engineering - Research and Technology	X		
Conduct of Inspection & Maintenance Services	X		X
Component & Equipment Surveillance			X
Software		X	
Items & Services Management		X	
Risk & Reliability			X
Equipment Reliability			X
Reactor Safety		X	
Project Management	X		
Major Components			X

Engineering Change Control	X		
Environmental Qualification	X		
Chemistry		X	
Welding			
Integrated Aging Management			
Decommissioning		X	
Nuclear Waste Management Program		X	
Nuclear Operations	X	X	X
Heavy Water Management			
Nuclear Operations (Fuel Handling)			X
Conduct of Maintenance	X	X	X
Work Protection		X	
Production Work Management		X	
Fire Protection		X	X
Training	X		X
Human Performance		X	
Corrective Action			X
Radiation Protection		X	
Health & Safety Management System Program			X
Environmental Management	X	X	
Nuclear Pandemic Planning	X		
Design Management			X
Nuclear Security (with Nuclear Safeguards)	X		
Radioactive Material Transportation		X	
Consolidated Nuclear Emergency Plan		X	X
Business Planning	X		
Records and Document Control			
Nuclear Safeguards (with Nuclear Security)	X		
Fuel			X
Managed Systems		X	
Conduct of Regulatory Affairs	X		
Independent Assessment (NIEP)			X
Component Equipment Surveillance (DNR only)		X	
Safety System Functional Audit (DNR only)			X

Nuclear Oversight audit reports are distributed to the senior management team within Nuclear (SVPs, VPs, Directors) and to line management who have been involved with audit.

2) <u>Internal Audit</u>

For 2016, Internal Audit will perform the audits set out in Chart 5 relating to the DRP. The 2017 to 2019 Audit Plan relating to DRP is provided in Chart 6.

Chart 5 – 2016 Internal Audit Plan

No.	Engagement Name	Status
1	DNR Onboarding	Complete
2	DNR Project Management	Complete
3	DNR Contractor Invoicing	Complete
4	DNR Contractor and Subcontractor Management	Complete
5	DNR Construction & Tooling - R&FR Project	Complete
6	DNR Engineering - Turbine Generator Project	Complete
7	DNR Integrated Database for Project Reporting	Complete
8	DNR Contractor Timekeeping	In Progress
9	DNR EPC Procurement	In Progress
10	DNR Project Revisions & Rework	In Progress
11	DNR Contractor Procurement - R&FR Project	Complete
12	DNR Project Cost Management System	In Progress
13	DNR Finance Controls	In Progress

Chart 6 – 2017 – 2019 Internal Audit Plan

Darlington Nuclear Refurbishment			
Year	2017	2018	2019
Program Management	Program Oversight & Reporting	Program Oversight & Reporting	Program Oversight & Reporting
	Vendor Productivity	Quality Management Program	-
Core Project Execution – Project Management	Retube & Feeder Replacement (“R&FR”) – Project Execution	Steam Generator – Project Execution	R&FR – Project Execution
	Fuel Handling – Project Execution	Turbine Generator – Project Execution	Turbine Generator – Project Execution
	Balance of Plant – Project Execution	-	Balance of Plant – Project Execution

The distribution for Internal Audit reports is as follows:

Reports are directed to:

- SVP, Nuclear Projects
- Other Executive Leadership Team Members (as applicable if their organization has ownership for actions)
- Process Owner for the Audit

Other stakeholders included on the distribution (copied) are:

- President & Chief Executive Officer
- SVP Finance, Strategy, and Chief Financial Officer
- Nuclear President & Chief Nuclear Officer
- SVP Nuclear Refurbishment
- VP Nuclear Finance
- Director Refurbishment Systems Oversight
- Director Nuclear Oversight
- Other impacted stakeholders (as applicable)

ED Interrogatory #27

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: Ex. F2, Tab 2, Schedule 3, Attachment 2, p. 16-18

(a) Please provide the detailed data and electronic spreadsheets underlying OPG's economic assessment of Pickering Continued Operations, including its assessment of the system economic value. The economic assessment appears at pages 12 to 14 of OPG's business case (using the numbering at the bottom right corner).

(b) As part of its assessment of the system economic value of continuing to operate Pickering until 2022/2014, did OPG consider the possibility of a contract for Quebec power as the primary source of replacement power for Pickering?

(c) Please redo OPG's system economic value analysis based on the assumption that replacement power is sourced primarily from an electricity import agreement with Quebec.

Response

(a) OPG assumes that the requested information relates to Pickering Extended Operations per Ex. F2-3-3 and not to Pickering Continued Operations.

Refer to Ex. L-6.5-1 Staff-125 and Ex. L-6.5-1 Staff-126 for the production, cost data and major assumptions used in the economic assessment as well as Attachment 1 for the detailed data.

Attachment 2 (provided only as an electronic spreadsheet) contains a spreadsheet that allows parties to modify assumptions about the Pickering costs that underlie OPG's economic assessment as presented in the Pickering Extended Operations Business Case.[1] This spreadsheet is provided pursuant to OPG's proposal in its Reply to Motions to address ED's request in part (a) of this interrogatory for electronic spreadsheets underlying OPG's economic assessment.

[1] Ex. F2-2-3, Attachment 2, pp. 16-18.

As OPG explained in its Reply to Motions (para. 49), this spreadsheet incorporates output from OPG's proprietary production model, but the system benefit data is hardcoded such that it does not allow parties to run alternative resource scenarios. It will, however, allow parties to modify assumptions about the costs of the project.

The spreadsheet contains formulae and acronyms which are familiar to users trained in the spreadsheet, but which may not be properly understood by others. Because of the complexity of the spreadsheets, OPG cannot warrant the accuracy of the results obtained by any manipulation of the spreadsheets conducted by third parties.

(b) OPG's economic assessment did not consider a contract with Quebec Power as a primary source of replacement power for Pickering.

(c) OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on the costs of hypothetical alternatives to Pickering Extended Operations. Such information is not relevant to deciding any issue on the approved Issues List in this application. An investigation into alternatives to Pickering Extended Operations is not within scope of the Issue 6.5. In rejecting attempts to broaden Issue 6.5, the OEB clearly stated that this issue is intended to address "consideration of the test period expenditures for Pickering Extended Operations." (Decision on Issues List, September 23, 2016, page 7). Moreover, OPG does not have the information necessary to perform the requested analysis and any attempt to develop this information would be speculative, depending entirely on assumptions about the cost and characteristics of a hypothetical future import agreement between the Provinces of Quebec and Ontario. See Ex. L-6.5-7 ED-40.

Board Staff Interrogatory #189

Issue Number: 6.10
Issue: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Interrogatory

Reference:
Ref: Exh F4-2-1, page 10, Table 3a and Exh H1-1-1, pages 11-12

Page 10 indicates that OPG recognizes 75% of the estimated ITCs for taxation years that are subject to audit. To the extent the ultimate percentage of recognition for SR&ED ITCs differs from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG records the difference in the Income and Other Taxes Variance Account.

a) Please confirm that the variance account is only to true up the 75% to the percentage of recognition resulting from a tax audit and is not a true up to the actual SR&ED credit claimed.

b) Please indicate how often SR&ED audits occur.

c) OPG has forecasted SR&ED ITCs to be $18.4M for each year from 2017 to 2021.
   i. Is this amount 75% of the total estimated SR&ED ITC?
   ii. Please explain how the $18.4M SR&ED ITC was derived and why OPG proposes that it be the same amount each year from 2017 to 2021.

d) Please provide a comparison of forecasted and actual SR&ED from 2013 to 2015.

e) OPG has forecasted additions for Taxable SR&ED ITCs to be $18.4M each year from 2017 to 2021 and deductions for SR&ED Qualifying Expenditures to be $27.7M each year from 2017 to 2021.
   i. Please explain how these amounts were derived and why OPG proposes it to be the same amount each year from 2017 to 2021.
   ii. Please explain the correlation between the forecasted additions, deductions and ITC amounts relating to SR&ED in Table 3a.

Response

a) Confirmed

b) OPG's income tax returns, which include SR&ED ITC claims, are audited by the Ontario Ministry of Finance for each taxation year.

c)

i. Yes, $18.4M represents 75 percent of total estimated SR&ED ITC amounts attributed to the nuclear operations.

ii. For business planning purposes, OPG estimates future SR&ED ITCs based on actual SR&ED ITCs of a recurring nature earned in the last taxation year for which tax returns have been filed at the time the estimate is prepared, plus forecast amounts of a non-recurring nature (if any) provided by technical personnel for certain identified work. OPG does not rely on historical actuals as the basis for the non-recurring amounts given that the nature and volume of this type of work can change significantly year over year.

The last year for which tax returns were filed at the time OPG developed the estimate reflected in this application was 2014. Actual ITCs of a recurring nature for 2014 (as attributed to the nuclear operations and subject to the 75 percent recognition) were $19.2M. No amounts of a non-recurring nature were identified by technical personnel in the nuclear business unit. Therefore, the amount of $19.2M, as adjusted to $18.4M for the reduction in the Ontario ITC rate from 4.5% to 3.5% effective June 1, 2016 (see Ex. F4-2-1, section 3.4, lines 4-6), was used as the estimate for all years of the IR term.

Since the filing of its application on May 27, 2016, OPG developed an updated estimate of the 2017-2021 SR&ED ITCs as part of the 2017-2019 Business Plan. The updated estimate was developed based on the 2015 tax return, in the same manner as described above. As requested by OEB Staff at the Technical Conference, Day 3 (Tr. p. 72, lines 23-27), OPG is providing this updated estimate.

The SR&ED ITCs for the nuclear facilities reflected in the 2017-2019 Business Plan are $26.3M for 2017, $26.5M for 2018, $26.9M for 2019, $27.5M for 2020, and $25.3M for 2021.

d) A comparison of the forecasted SR&ED ITCs and actual SR&ED ITCs earned for 2013 to 2015 for the nuclear operations is as follows (pre-tax):[1]

Year	Forecasted ITCs ($M)	Actual ITCs Earned ($M)[2]
2013	14.1[3]	35.5
2014	9.4[4]	33.0
2015	9.4[5]	31.9

e) (i) & (ii)

As discussed at Ex. F4-2-1, section 3.4, OPG is subject to federal and provincial tax on SR&ED ITCs. As such, the Taxable SR&ED ITCs addition to earnings before tax is included in the calculation of regulatory taxable income. The forecasted amount of Taxable SR&ED ITCs reflects the forecasted amount of SR&ED ITCs for the corresponding years. Specifically, the Taxable SR&ED ITCs at Ex. F4-2-1, Table 3a, line 9 were determined by including the Ontario ITCs earned in the current year and the federal ITC utilized in the previous year, and therefore are correlated to the SR&ED ITC amounts at Ex. F4-2-1, Table 3a, line 25. The derivation of the $18.4M in forecast SR&ED ITCs is explained in part (c).

The deduction for SR&ED Qualifying Expenditures is on account of SR&ED qualifying expenditures of a current nature that are capitalized for accounting purposes but are deductible for income tax purposes. These amounts are estimated for business planning purposes based on actual historical expenditures of a recurring nature, plus forecast amounts of a non-recurring nature (if any) identified by technical personnel in the nuclear business unit. No amounts of a non-recurring nature were identified as part of the 2016-2018 business planning cycle. The above approach yielded a forecast of $27.7M per year for the IR term. These expenditures, along with qualifying expenditures of a current nature expensed for accounting purposes, are the underlying expenditures giving rise to the SR&ED ITCs.

[1] As discussed at Ex. F4-2-1 section 3.4 and in part (e) of this interrogatory, SR&ED ITCs are taxable. Therefore, the full effect of SR&ED ITC variances on income tax expense would be net of tax on amounts shown in part (d).
[2] For 2013 and 2014, Attachment 1, Table 1, line 1 of Ex. L-6.10-1 Staff-188. The 2015 value is based on the 2015 income tax return which was completed subsequent to the filing of this application.
[3] Nuclear portion of EB-2013-0321 Ex. F4-2-1, Table 5, line 24, col. (a).
[4] EB-2013-0321 Ex. L-6.13-1 Staff-165, Att. 1, Table 1, line 24, col. (c).
[5] EB-2013-0321 Ex. L-6.13-1 Staff-165, Att. 1, Table 2, line 24, col. (c).

SEC Interrogatory #95

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory

Reference:
SEC seeks to understand the interplay between the proposed rate-setting mechanism and the Hydroelectric Capacity Refurbishment Variance Account:

a. Please provide a list of all planned capital projects and their costs that are expected to be in-service between 2017 and 2021 that would be subject to the Hydroelectric Capacity Refurbishment Variance Account.

b. For each year between 2017 and 2021, please provide OPG's forecast total hydroelectric in-service additions.

c. Please explain how OPG has taken into account the Hydroelectric Capacity Refurbishment Variance Account in its determination of the appropriate incentive rate-setting adjustment for hydroelectric payment amounts.

Response

a) b) and c)

Incentive regulation decouples revenues and costs. The CRVA retains the link for a specific category of capital costs (i.e., capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish, or add operating capacity to a generating facility). The CRVA removes any potential economic disincentive to invest in a category of projects. As such, OPG is of the view that in addition to being required to implement O. Reg. 53/05, the CRVA is consistent with incentive regulation. Current approved rates include an amount associated with CRVA projects which will form the reference amount to be used for the CRVA. OPG's actual costs will be recorded in the CRVA regardless of whether they are included in OPG's current forecasts; therefore forecasts of specific projects or in-service amounts are not relevant. As the CRVA is consistent with IR, and OPG has followed the price-cap option as defined in the RRFE, no adjustment is necessary and none is proposed.

Although OPG does not believe it is relevant to this proceeding, OPG has provided the information in requested in parts (a) and (b) in Charts 1 and 2, below.

Chart 1 lists the regulated hydroelectric capital projects currently expected to be fully or partially placed in service between 2017 and 2021 for which incremental revenue requirement is expected to be included in the CRVA. Chart 1 also includes the in-service amounts and total revenue requirement impact (including income tax deductions for Capital Cost Allowance) estimated for each of these projects during the 2017-2021 period.

Chart 1: CRVA-Eligible Projects - Expected In-Service Additions (Regulated Hydroelectric)

Project Name	In-Service Date(s)	Expected In-Service Additions (2017-2021) ($M)	Estimated Revenue Requirement Impact (2017-2021) ($M)
Sir Adam Beck I GS - G10 Major Overhaul & Upgrade	2017	30	10
Sir Adam Beck Pump GS - Reservoir Refurbishment	2017	58	24
DeCew Falls II GS - G2 Overhaul & Upgrade	2018	38	10
Ranney Falls GS Expansion Project	2019	65	-4
Sir Adam Beck I GS - G8 Major Overhaul & Upgrade	2020	27	3
Sir Adam Beck I GS - G2 Frequency Conversion	2020	43	5
Sir Adam Beck I GS - G1 Frequency Conversion	2021	45	2
R.H. Saunders GS - Reinsulate Field Poles	2019, 2020 & 2021	4	0
R.H. Saunders GS - Replace Discharge Rings	2019, 2020 & 2021	7	1
R.H. Saunders GS - Replace Runners	2019, 2020 & 2021	10	1
Stewartville GS - Rewind Generators & Refurbish Field Poles	2020 & 2021	9	1
		335	**52**

*Numbers may not add due to rounding

Chart 2 presents OPG's current expectation of total regulated hydroelectric in-service additions for the 2017-2021 period.

Chart 2: Expected Total In-Service Additions (Regulated Hydroelectric)

($M)	2017	2018	2019	2020	2021
	182	178	186	211	195