UNDERTAKING J1.1

Undertaking

To produce the Burns & McDonnell/Modus report provided to the November meeting on a confidential basis.

Response

A copy of the report is provided in Attachment 1 (confidential).

Executive Summary

Breaker Open and the start of the Darlington Refurbishment Project ("DR Project") Execution Phase occurred on schedule. OPG Management's November 10, 2016 report ("Management Report") to the DRC affirms the DR Project remains within the overall RQE control budget of $12.8 billion and that the DR Project's overall P90 schedule duration of 112 months is not challenged. The Management Report to the DRC adequately reflects the status of the Project and is generally focused on the DR Project's current key status points and risks. Over 3Q 2016, OPG's assurance programs have been effective at identifying issues. The DR Team has established a number of critical initiatives intended to improve work flow, accountability and overall management of the work in the field, the success of which will be monitored.

Looking forward, the Burns & McDonnell/Modus External Oversight Team ("EO Team") has identified certain issues that could have an impact on the Project if they are not addressed, including:

- The schedule for non-critical path work needed for reactor vault turnover being performed simultaneously with Defueling requires a significant ramp-up of resources, and the vendors' capability to support the schedule will require monitoring in light of past performance trends.
- While reporting has improved, OPG's method for verifying quantities of work performed and tracking of productivity would benefit from a focus on contractor direct work (or "wrench") hours and regular verification of contractors' actual hours performed by work package;
- Functional staffing levels remain below target; with ongoing efforts to fill the open positions, there are short-term needs to close resource gaps and meet challenges to integrate new hires into the DR Team;
- Contract Management activities need to progress while OPG implements a long-term strategy.

Evaluation of DR Project Status

The EO Team has identified the following key status points as of October 28th that should be considered for purposes of evaluating the DR Project's health as a whole.

Key DR Project Status Indicators	
Schedule Performance	OPG's work is on the critical path for a planned 167 days from Breaker Open to turnover of the vault to SNC/AECON on March 30, 2017 ("Segment 1"). The DR Team met its first challenges in the first week following Breaker Open and has responded well to issues as they developed. While the critical path Defueling work is currently on schedule, other non-critical path work is tracking behind the Project's P50 Schedule. While we see no current risk to the P90 Schedule, there has been a reduction of available schedule float for non-critical path work. Focusing solely on construction progress, as of Breaker Open, the DR Project had completed 10.3% of field work (including station pre-requisite projects) against a planned 12.3%, yielding an SPI for construction activities of 0.84. In August, management evaluated the priorities for Breaker Open and moved some non-critical pre-requisite work into Segment 1. Performance of other preparatory and pre-requisite work will require a ramp-up of resources and improved performance, as discussed below in Vendor Performance.
Cost Performance	The DR Team has maintained the 4-unit Project control budget of $12.8 billion through completion of the Unit 2 Estimate. The final Unit 2 Execution Phase schedule was baselined on September 16, 2016, resulting in minor changes to internal cost categories within the Unit 2

	budget, but with no impact on the control budget or the P90 schedule. There were some contingency draws, notably for the Shut-down Layup ("SDLU") bundle, totaling $25M for Unit 2 and $80M overall, which were based upon ES Fox's updated estimates that included added scope and work forecasts since RQE. The Unit 2 budget is $3.4 billion with $677 million contingency.
Vendor Performance	Within Segment 1, the major contractors have non-critical path work needed to prepare the vault for turn-over on or before March 30, 2017. ❖ SNC/Aecon's new Site Director has initiated a number of positive changes, and the RFR team has identified potential performance improvements that could improve both cost and schedule. SNC/Aecon is also addressing resource gaps and optimizing its organization for execution. SNC/Aecon's progress on the Reactor Waste Processing Building ("RWPB") remains on schedule. SNC/Aecon's scope has increased in Segment 1 to incorporate the unit islanding and support tasks which will be required for vault turnover, though this is simply a transfer of existing scope and the overall Unit 2 cost is unchanged. ❖ [redacted]
Project Controls and Risk Management	The Project Controls Team has implemented systems for managing and controlling the work that are representative of industry best practices. The team is currently performing quality control checks to ensure full cost and schedule reporting alignment, which may take several more weeks or months, though this effort is essential to ensure that the reports generated are accurate. With respect to Risk Management, in our August report we identified that certain technical performance risks were added post-RQE. The DR Team is reporting that it is managing these risks. In addition, the DR Risk Team is providing increased focus on risk mitigation and is receiving support from DR Management and Corporate Enterprise Risk Management.
Safety and Quality	The DR Team has identified an increase in safety events, and as a result the DR Team has increased its focus on identifying controls and field processes in order to increase risk-based oversight of the vendors' activities as appropriate. OPG has established a number of field protocols aimed at monitoring the contractors' work which, if effective, should enhance tracking of performance and mitigate safety and quality issues, though these processes need to be tested in the field.
Construction Checkout and Testing	The DR team is increasing focus on vendor performance associated with Construction Checkout and Test ("COAT") and Construction Completion Declaration ("CCD"). Properly performing the COATs and assembling and reviewing all associated documentation is a comprehensive effort that can impact the schedule if not addressed timely. Completing COAT and CCD activities for the Breathing Air System presents a critical near term opportunity to measure performance and adjust processes.

Project and Program Assurance

The DR Team's Performance Assurance Group ("PAG"), Enterprise Risk Management and OPG Internal Audit have developed and are executing robust plans for assurance activities. Within the quarter, PAG prepared a root cause assessment of vendors' CWPs development, identifying negative trends and repeated issues. In response, the DR Team introduced oversight initiatives focused on improving communications, increasing accountability and changing some of the outage-based behaviours. These initiatives have promise though their impact on the work will need to be proven.

OPG Project Team

OPG's Project leadership has implemented the Division of Responsibility for all work groups and a number of new processes focusing on improving accountability that grew out of OPEX from the Readiness to Execute period. The DR Team and the vendors have had multiple field readiness reviews/challenges to ensure the workers have the necessary tools, equipment and support to effectively execute the work, in order to enhance schedule and budget performance.

OPG remains under-staffed based on its U2EE projections. The current plan calls for OPG to add resources from its current level of [redacted] in Q1 2017. OPG's ability to hire, train and integrate these new hires into the current staff will be a challenge in the coming months.

Project Risks and Strategic Considerations

The EO Team offers the following analysis of certain forward-looking risks and strategic considerations that could impact the P90 schedule. OPG's assurance providers (including our team) have encouraged the DR Team to move from an outage to a construction mindset; the DR Team's leadership agrees that there is a need to implement more of a traditional Project execution model. To that end, the following are opportunities for improvement:

Risk Area	EO Team Observations
Performance Reporting	Performance reporting relies upon the vendors to accurately report progress and the owner's validation. As noted, OPG has the systems and resources in place to support performance reporting; however, OPG Management should consider the following improvements to more accurately analyze and measure the DR Project's status and craft labour productivity: ❖ The DR Team's focus on daily scheduled task completion, which is an outage trait, needs to be paired with a focus on the resource hours needed to perform the direct work (aka "wrench hours") and percent completion of work over time. This transition is in progress. ❖ OPG needs its vendors to report their actual field execution hours in a method consistent with how they report earned value progress. OPG management is addressing this with its vendors. However, until this gap is corrected, OPG will lack a powerful tool to hold the vendors accountable to their work estimates.
Commercial Management	OPG is currently assessing a company-wide enterprise approach to commercial management. In the meantime, there will be a significant increase in the volume of work associated with

	documenting and tracking potential commercial issues, including: initiating, responding and tracking correspondence with vendors; tracking contractual milestones; monitoring schedule and performance issues; providing prompt notice of vendor deficiencies; and assisting in supporting the OEB case. The current Contract Management team has capable leadership, though the planned out-sourcing of the resources to fill this function needs to be progressed.
Vendor Performance	The performance by some of the vendors to date presents risks to Segment 1 and beyond if not mitigated. ❖ As noted, for the current Segment 1 work, from September to November 2016, ES Fox will need to ramp-up its weekly earned value production to meet the schedule and then maintain that level of progress through the first half of the Unit 2 DR Project. [redacted] Based on performance trends to date, the EO Team sees a risk that BOP and SDLU work could place greater demands on management's time and could impact key project milestones. This trend should be monitored closely. ❖ SNC/Aecon is currently preparing for vault turnover, unit islanding work and completing the RWPB, all of which support its critical path retube and feeder replacement work. SNC/Aecon is also performing rehearsal work in the vault mock-up with the goal of testing and improving its performance. [redacted] SNC/Aecon's new site leadership has instituted changes and increased accountability within the organization to address these issues.

UNDERTAKING J1.2

Undertaking

To produce the most recent version of the quarterly program performance information.

Response

A copy of the report is attached as Attachment 1 (confidential).

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

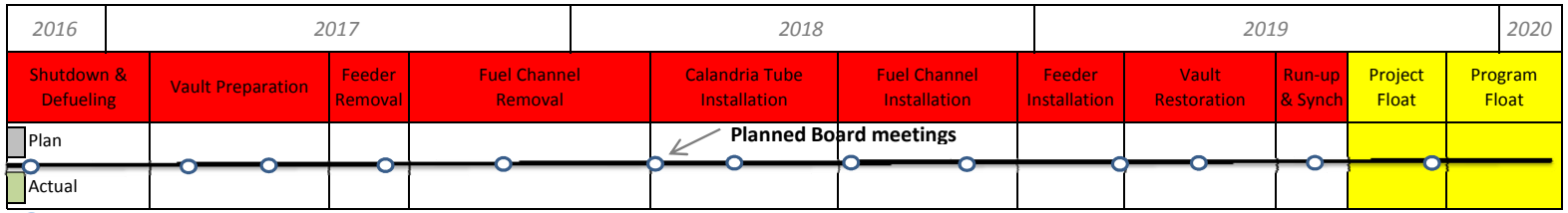
APPENDIX 1: CRITICAL PATH SCHEDULE PERFORMANCE

Performance of Critical Path against Working and High Confidence Schedule

Period Ending: 28-October-2016

OVERALL UNIT 2 STATUS

U2 Critical Path Series



	Shutdown & Defueling	Vault Preparation	Feeder Removal	Fuel Channel Removal	Calandria Tube Installation	Fuel Channel Installation	Feeder Installation	Vault Restoration	Run-up & Synch	Project Float	Program Float
Days Ahead / (Behind) Schedule	(1) 0										
Plan Duration (days) **1231**	114	141	66	192	147	141	96	108	65	45	115
Working Schedule Series Completion Date	6-Feb-17	27-Jun-17	1-Sep-17	12-Mar-18	6-Aug-18	25-Dec-18	31-Mar-19	17-Jul-19	20-Sep-19	4-Nov-19	27-Feb-20
High Confidence Schedule Series Completion Date	19-Feb-17	2-Aug-17	19-Oct-17	2-Jun-18	13-Nov-18	18-Apr-19	7-Aug-19	5-Dec-19	27-Feb-20	Not Applicable	
Forecast /Actual Series Completion	(2) 6-Feb-17	-	-	-	-	-	-	-	-	(4) 0	0%
Forecast / Actual Series Duration	114	-	-	-	-	-	-	-	-		
Variance from Working Schedule Plan ahead / (behind)	0	-	-	-	-	-	-	-	-		
Variance from High Confidence Schedule Plan ahead / (behind)	(3) 13	-	-	-	-	-	-	-	-	**Float Used**	**% Used**

STATUS OF CRITICAL PATH

(1) Critical path is through the Shutdown and Defueling series. As at October 28, critical path is slightly ahead of the working schedule. Details on current series performance are provided in Appendix 2 - Current Critical Path Series.

(2) Forecast completion of the series remains as per working schedule.

(3) Forecast completion of the series is 13 days ahead of the high confidence scheduled completion.

(4) As at October 28, zero schedule float has been allocated to the project.

STATUS OF NON CRITICAL PATH ACTIVITIES

There is currently a low risk of non-critical path activities becoming critical path.

Non-critical path activities in progress include lay-up of the conventional (non-radiological) systems in which the systems are drained and protected from corrosion; and completion of the in-station pre-requisite projects that were re-scheduled into the Unit 2 Refurbishment. Currently, 12 of 25 pre-requisite projects are complete, and the remaining 13 projects are on track to meet their schedule completion dates.

Other non-critical path activities include the Vault Vapour Recovery System valve replacement, work protection permitry for the conventional side of the station and pre-requisite activities on the Re-tube and Feeder Replacement and Turbine Generator projects.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Series

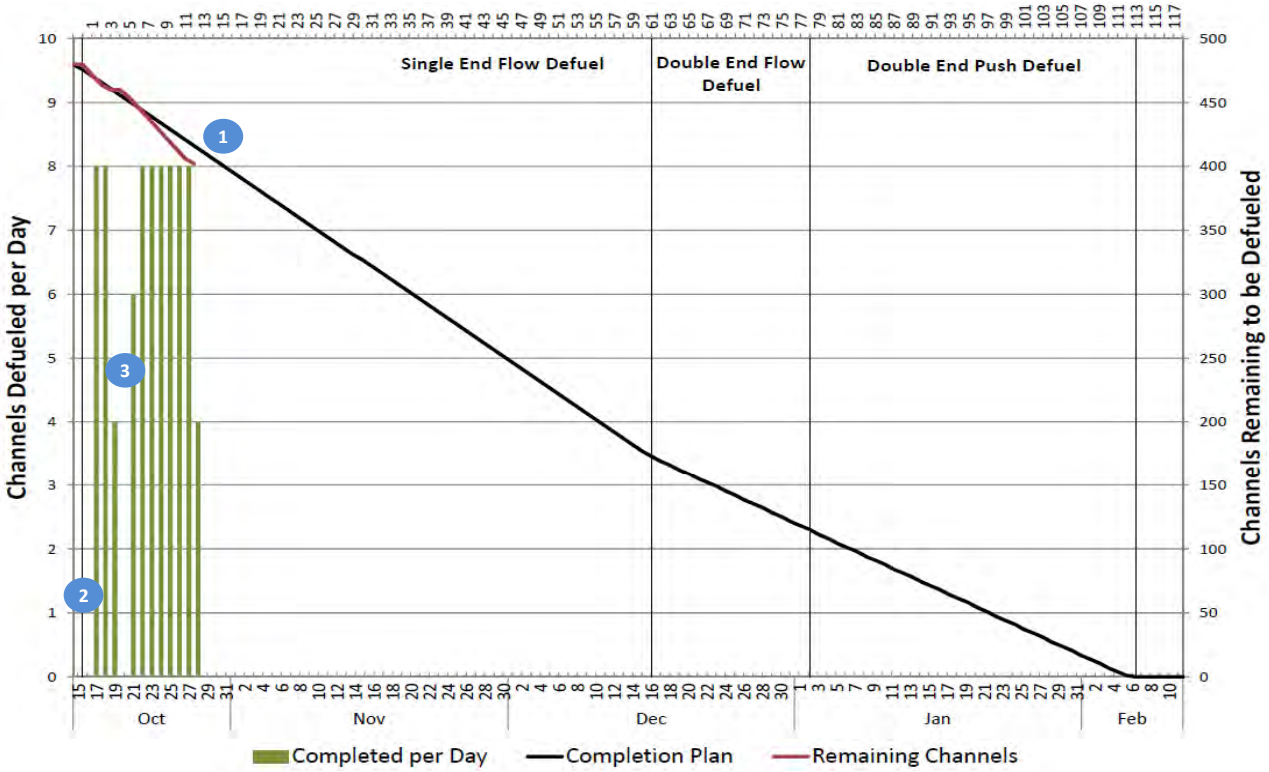
APPENDIX 2: CURRENT CRITICAL PATH SERIES PERFORMANCE

Detailed Status of the Current Series Including Commodity Installation/Removal

Period Ending: 28-Oct-2016

CRITICAL PATH SERIES

SHUTDOWN & DEFUELING	The first critical path series includes the shutdown of the unit, and the safe removal of all fuel from the reactor core in a cost effective manner in order to minimize outage duration. Flow defueling is the preferred method to defuel the reactor and relies on flow of the primary heat transfer coolant over fuel to "wash" fuel into fueling machine.
IN PROGRESS	



Series Completion	Working Schedule	High Confidence Schedule	Forecast	Variance to Working Schedule
Series Duration (days)	114	127	**114**	**0**
Series Completion Date	6-Feb-17	19-Feb-17	**6-Feb-17** (4)	**0**

Channels Defueled	Working Schedule	Actual	Variance to Working Schedule
# Channels	60	**78**	**+18** (5)
% Complete	12.5%	**16.3%**	**3.8%**

EXPLANATORY NOTES

1. Current performance, as at October 28, is ahead of the working schedule.
2. The reactor was shut down event-free on October 15, as planned; however the commencement of the defueling campaign was delayed by 1 day due to challenges with cooling the heat transport system to the specified temperature. This delay is now fully recovered.
3. Defueling was temporarily halted to accommodate planned maintenance on the defuel trolley, and the planned installation of reactor start-up instrumentation to allow continuing monitoring of the core.
4. The forecast completion of the Shutdown and Defuel Series is February 6, 2017 as planned.
5. As at October 28, an additional 18 channels were defueled compared to plan.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 3: KEY MILESTONES - UNIT 2 EXECUTION

Significant Unit 2 Critical Path Execution Milestones

Period Ending: 30-Sept-2016

PROGRAM MILESTONES

Line	Milestone	Working Schedule	High Confidence	Forecast/ Actual	Status	Explanatory Note
1	Unit 2 Breaker Open	15-Oct-16	15-Oct-16	15-Oct-16	COMPLETE	
2	Defuel Complete	6-Feb-17	19-Feb-17	6-Feb-17		
3	Bulkheads Installed	24-Mar-17	11-Apr-17	24-Mar-17		
4	Start of Feeder Removal Window	27-Jun-17	2-Aug-17	27-Jun-17		
5	Re-tube Waste Processing Facility In Service	15-Jun-17	31-Jul-17	15-Jun-17		
6	Feeder Removals Complete	1-Sep-17	19-Oct-17	1-Sep-17		
7	Fuel Channel Removals Complete	12-Mar-18	2-Jun-18	12-Mar-18		
8	Calandria Tubes Installed	6-Aug-18	13-Nov-18	6-Aug-18		
9	Fuel Channels Installed	25-Dec-18	18-Apr-19	25-Dec-18		
10	Feeders Installed	31-Mar-19	7-Aug-19	31-Mar-19		
11	Vault Restoration Complete	17-Jul-19	5-Dec-19	17-Jul-19		
12	Low Power Testing and Heat Up Complete	21-Aug-19	25-Jan-20	21-Aug-19		
13	Unit 2 Synchronized To Grid	10-Sep-19	16-Feb-20	10-Sep-19		
14	Unit 2 Returned to Operations	20-Sep-19	27-Feb-20	20-Sep-19		

On Plan for Working Schedule Date

Past Working Schedule Date but on or Before High Confidence Schedule Date

Past High Confidence Schedule Date

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 4: UNIT 2 PRE-REQUISITE PROJECT PERFORMANCE

Completion Status of In-station Pre-requisite Projects

Period Ending: 30 Sept 2016

PROGRAM MILESTONES

Line	Milestone	High Confidence Date	Need Date	Status	Explanatory Note
1	73455 – Calandria Seal Replacement			COMPLETE	
2	73370 - Powerhouse Steam Venting System			COMPLETE	
3	73711 – Work Control Area			COMPLETE	
4	73380 – Unit 4 Shield Tank Over Pressure Protection			COMPLETE	
5	73398 – Replacement of Emergency Service Water Line 60			COMPLETE	
6	73740 – Installation of Unit 2 Wi-Fi			COMPLETE	
7	73380 – Unit 3 Shield Tank Over Pressure Protection			COMPLETE	
8	73472 – Primary Heat Transport Header Tie-ins			COMPLETE	
9	31710 – Shutdown Cooling Heat Exchanger			COMPLETE	
10	73741 – Negative Pressure Containment Islanding			COMPLETE	
11	73712 – Radiation Protection Office			COMPLETE	
12	73467 – Construction Island Barriers			COMPLETE	All field work complete.
13	73769 – Adjustor Rod SHIM (Unit 1, 3, 4)	15-Oct-16	8-Feb-17		Project was installed as per the commitment; however, a design issue was identified which prevents SHIM mode from being declared available. A path forward has been established which supports SHIM being made available by bulkhead installation in February 2017.
14	73716 – Additional Washrooms	7-Jan-17	6-Feb-17		
15	73715 – Non Contaminated Work Shops	11-Jan-17	6-Feb-17		
16	73113 – RFR Primary Heat Transport Header and Bellows	30-Jan-17	23-Mar-17		
17	73592 – Vault Vapour Recovery System	15-Feb-17	23-Mar-17		
18	73742 – Decontamination Room S107 Upgrade	25-Feb-17	25-Feb-17		
19	73545 – Dry Air for Conventional Systems	28-Feb-17	28-Feb-17		
20	73538 – Service Air Capacity Enhancement	1-Mar-17	1-Mar-17		
21	73277 – Turbine Crane Inspections and Repairs	15-Mar-17	15-Mar-17		
22	73643 – Unit Power Electrical Distribution System	12-Apr-17	12-Apr-17		
23	73537 – Breathing Air Capacity Enhancement	24-Mar-17	15-Apr-17		Risks associated with the completion of design, and material delivery are being actively managed by the project teams to ensure that the breathing air enhancement is in-service by the need date.
24	73113 – RFR Power and Infrastructure	15-Jun-17	15-Jun-17		
25	73714 – Contaminated Shops and Scaffold Storage	30-May-18	30-May-18		

On Plan for High Confidence Date

Past High Confidence Date But on or Before Need Date

Past Need Date

ONTARIO POWER GENERATION

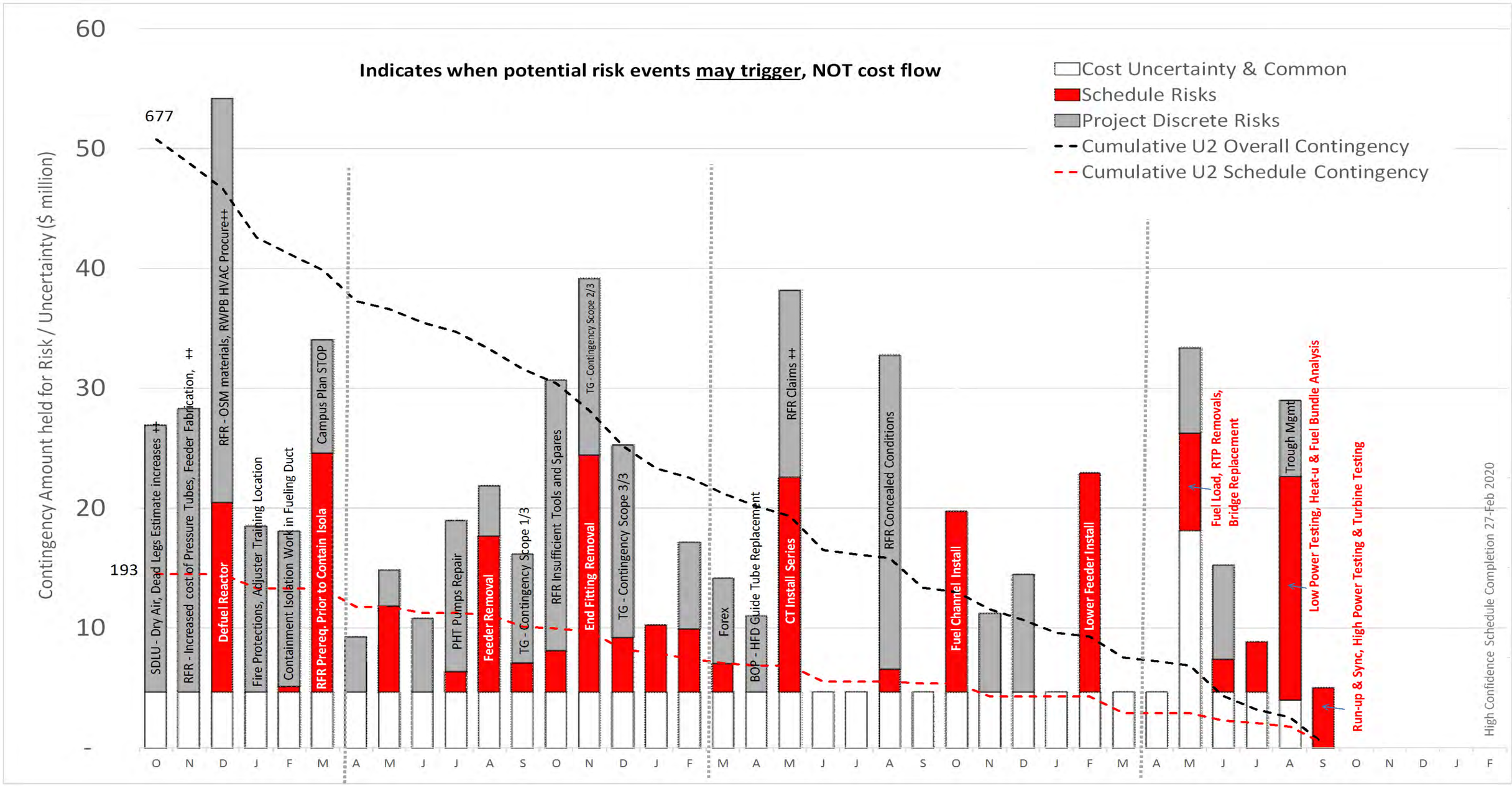
Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 6: RISK MAPPING FOR UNIT 2 EXECUTION

Risk Events and Contingency ($) Mapped to the Unit 2 Working Schedule

Period Ending: 30-Sep-2016

RISK MAPPING



	Lead In			Removal												Inspection & Installation																			Lead Out						Float Contingency 5 Months				
Year	2016			2017												2018																			2019										
Month	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F
Project Discrete Risks	22	24	34	14	13	9	5	3	6	13	4	9	23	15	16	-	7	7	6	16	-	-	26	-	-	7	10	-	-	-	-	7	8	-	6	-	Schedule Impacts will shift base + contingency costs into the 5 month float period				
Schedule Risks	-	-	16	-	0	20	-	7	-	2	13	2	3	20	5	6	5	2	-	18	-	-	2	-	15	-	-	-	18	-	-	8	3	4	19	5					
Cost Uncertainty & Com	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	18	5	5	4	-					
Total by Segment	**180**			**214**												**187**												**96**										**677**				
%	27%			32%												28%												14%										100%				

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 7: KEY TECHNICAL RISKS FOR UNIT 2 EXECUTION

Technical Risks Being Actively Managed by the Program

Period Ending: 30-Sep-2016

KEY PROGRAM RISKS AND MITIGATION STATUS

Line	Status	Risk Description	Mitigation Plan
1	–	**Foreign material in the Primary Heat Transport (PHT) System leading to fuel defects impacting refurbishment** Foreign material within the PHT system damages assets or creates fuel defects, resulting in cost and schedule impacts	There is a risk that upon completion of the refurbishment installation series it is discovered that the implementation of the foreign material exclusion programs were less than adequate, resulting in the potential for foreign material inclusion damaging the asset or increasing the risk of fuel defects. This would result in a need to flush the PHT system and hot condition the fuel, and will have a direct impact on the cost and critical path schedule. Fleet level engineering and operations analysis is currently underway to fully assess the risk. Mitigation strategies to perform crud bursts and chemistry controls are underway. Flush and hot conditioning is being planned for within the Unit 2 critical path schedule, and ultra-clean foreign material exclusion principles are being applied into the work planning and training. Engineering ultra-clean specs are well underway, and Refurbishment Maintenance, along with Refurbishment Construction, is in progress of developing detailed implementation plan to meet the ultra-clean foreign material exclusion specifications.
2	–	**Significant discovery work inside the Calandria impacting the refurbishment schedule**	There is a risk that a large amount of discovery work is identified upon inspection of the inside of the Calandria vessel. This will have a direct impact on cost and schedule delays to the re-tube removal and/or install segment of critical path. This would be caused by concealed conditions and limitations in the ability to examine/inspect Calandria internals prior to refurbishment. Limitations to inspection (concealed condition) imply that nothing further can be done, beyond internal Operating Experience (OPEX) reviews and chemistry analysis to determine conditions within the Calandria that may require remediation, which is underway. This is a High Impact Low Probability risk. Contingency has been allocated in the event that the risk is realized during Unit 2 inspection.
3	–	**Hoisting or rigging failures resulting in worker injury or schedule delays**	The Refurbishment project includes significant hoisting and rigging activities such as turbine spindle lifts and lifts over the vault during execution. These lifts put personnel at risk of injury or death and the project at risk of schedule delay and cost impact if not executed event-free. Recent industry OPEX, such as the fatality at Arkansas One NGS, indicates that there is a need to apply extensive rigor and detail in the critical lift program. Mitigation to date includes OPEX reviews and integration by the vendors performing Turbine Generator lift work and focus on communication and integration of INPO Event Report - Lifting, Rigging, and Material-Handling Concerns. All Critical Lift Plans are reviewed by Engineering and Safety and subsequently accepted by OPG Civil Engineering and Conventional Safety. The Hoisting and Rigging subject matter expert will do a final review and approval for use to ensure proper rigor is built into lift plans.
4	–	**Primary Heat Transport (PHT) pump breakdown stopping flow defueling process** Planned flow defueling would be unavailable requiring use of push defueling, and extension to the critical path.	There is a risk of failure of one of the PHT pumps which would make the planned flow defueling impossible, requiring the use of dummy bundle push defueling for the entire reactor greatly extending the schedule and therefore cost of the project. Multiple forms of risk mitigation are currently underway, including reactor safety examination of the possibility of running three pumps instead of four. It is confirmed that the action resulting from a PHT motor failure will be to replace the motor, or move to push defueling. Contingency dummy fuel bundles, which will be used for push defueling, are being fabricated and delivered to site prior to their potential need date.

– No change over period ↑ Improvement ↓ Decline High Risk Low Risk

ONTARIO POWER GENERATION

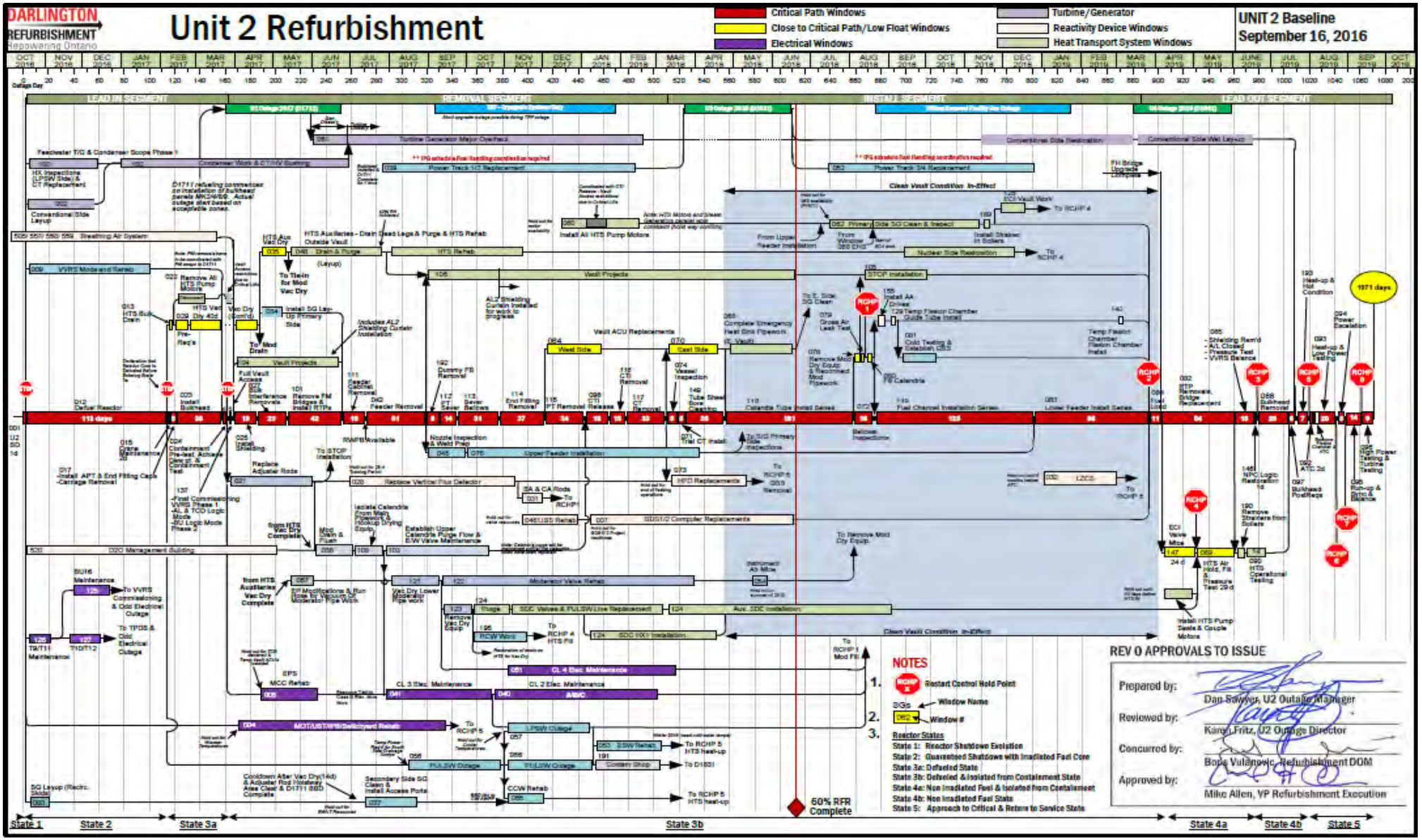
Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 8: UNIT 2 LEVEL 1 SCHEDULE

Baseline Schedule

Period Ending: 30-Sep-2016

Unit 2 Refurbishment



ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 9: UNIT 2 SEGMENT 1

Defuel and Containment Isolation

Period Ending: 30-Sep-2016

Unit 2 Refurbishment

DARLINGTON REFURBISHMENT Repowering Ontario

S1

Unit 2 Refurbishment: SEGMENT 1 Defuel + Containment Isolation

167 days: October 15, 2016 – March 30, 2017

Critical Path Windows
Electrical Windows
Conventional Layup
Heat Transport Vacuum Dry
Other required S1 work

Baseline U2 S1
September 16, 2016

October 2016 | November 2016 | December 2016 | January 2017 | February 2017 | March 2017 | April 2017

10/2 10/9 10/16 10/23 10/30 11/6 11/13 11/20 11/27 12/4 12/11 12/18 12/25 1/1 1/8 1/15 1/22 1/29 2/5 2/12 2/19 2/26 3/5 3/12 3/19 3/26 4/2 4/9

2 Conventional Side LAY-UP

Drain & Protect (Lay-up) Conventional Systems from Corrosion

To inhibit corrosion damage to secondary side steel piping systems caused by moisture, temporary dehumidified air is provided. (11) Dry Air skids will be installed at various points to force warm air through the pipework in order to achieve acceptable dryness.

Layup Completion for the following systems:

DHA1:	Main Condenser
DHA2:	Boiler Feedwater
DHA3-4:	Main Condensate
DHA5:	Main Steam
DHA6-7:	Extraction Steam
DHA8-9:	Main Steam Reheat
DHA10:	D/A, Condensate Make Up & Storage Tanks
HP1:	PFW Pumps(Main & Aux)

09-Jan-17 Systems Declared in Lay-up

21-Oct-16 OPS Apply Drain OTO's & Drain — 01-NOV-16 Install Dehumidifiers and Establish Airflow Path — 29-Dec-16 Commision and Dry Conventional System

Heat Transport Motors Disconnect and Uncouple 33120-PM1, PM2, PM3, PM4 — 5 days

Remove Heat Transport Motors — 5 days

Vault Access Coordination for HT Motors due to Vault Access restrictions during Critical Lifts

4 PRIMARY HEAT TRANSPORT SYSTEM VACUUM DRY

The entire HT system must be drained & dried before the retube of the reactor can begin. Once Operators have drained it through normal pipework, the Heat Transport system will be put under vacuum in order to 'boil off' the rest of the water. A Vacuum Drying Skid will be attached to the HT system to perform this. The water vapor will be condensed in receivers and sent through piping to the storage tanks outside of Unit 2. It is expected to take 40 days to completely drain & dry the HT system

11-Feb-17 Vac Dry Prereqs — 04-Mar-17 — 22-Mar-17 Heat Transport Vacuum Dry

Defuel Complete 06-Feb-17

HTS Bulk Drain

Containment Pressure Test Declared Complete 30-Mar-17

Unit 2 Shut Down 15-Oct-16

West RAB Brake Repair

Declaration that Reactor Core is Defueled Before Entering State 3a

STOP

Window 017 Install APF, End Fitting Caps & Radiation Shielding

E&W Carriage Removal Complete 17-Feb-17

Window 23 Bulkhead Installation

Bulkhead Installation Complete 24-Mar-17

STOP

First things first...

1 — 270 Channels: Single End Flow Defuel — 06-Dec-16 — 86 Channels: Double End Flow Defuel — 02-Jan-17 — 124 Channels: Double End PUSH Defuel — 2d — 9d — 35 days — 6d

To the start of Segment 2 Window 137

5d Calandria Seal Leak Test

08-Feb-17 Window 015 Vault Crane Maintenance Complete

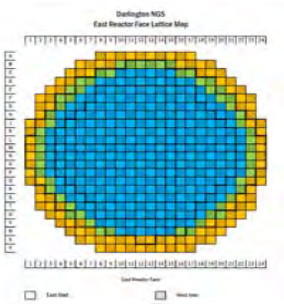
Window 24 Containment Pressure Test

Shutdown Unit 2

Unit 2 will start reducing power at 22:00 hrs on Friday Oct 14. At midnight (Oct 15th at 00:00 hrs) Operators will fire Shutdown System #2 to take the Unit deeply sub-critical. The Heat Transport System will be cooled down to 80 C to allow defueling of the reactor to take place. Years of planning has led us to this milestone to open the breaker on the first Darlington Refurbishment Unit!

1 DEFUEL

The reactor will be entirely defueled prior to turnover to the Joint Venture who are going to be performing the Retube of the Unit 2 reactor and replacing feeders. The majority of the defuel campaign will be accomplished via flow defueling using the Heat Transport pumps however it is estimated that 124 dummy fuel bundles (11 per channel) will need to be installed in the low flow channels allow push defueling to empty the channel.



3 'ISLAND' Unit 2 from the DNGS Operating Units

A large steel bulkhead to bridge the gap where the fueling machines access the U2 reactor will be installed during this window. This bulkhead will form part of the temporary containment boundary which will physically separate Unit 2's containment from the operting units.

5 VERIFY UNIT 2 is isolated from containment

The containment test is conducted to verify the integrity of the new containment boundary.

New Breathing Air System Installation

Install Mechanical Portion of Breathing Air System

Install Electrical – Breathing Air

Install Software and Computer Upgrades — Commission Breathing Air Outside Vault — 17-Jan-17

New Breathing Air Tie-in for Refurbishment use in Unit 2 will be performed at the start of Segment 2

Breathing Air Final Tie-in and AFS

Segment 1 Major Electrical Scope

21-Oct-16 W126: T9/T11 Maintenance — 11-Nov-16 W125: BU16 Maintenance — 10-Jan-17 To VVRS Commissioning and Odd Electrical Outage

15-Nov-16 W127: T10/T12 — 20-Dec-16 To TPDS and Odd Electrical Outage in S2

Window 009: VVRS Modifications

W009: VVRS Modifications — 29-Jan-17

To Containment Pressure Test

Window 100: Feedwater, T/G and Condenser Scope

W100: Feedwater, T/G and Condenser Scope

State 1: Reactor Shutdown Evolution | State 2: Guaranteed Shutdown with Irradiated Fuel Core | State 3a: Defueled State | State 3b: Defueled & Isolated from Containment State

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 10: CONVENTIONAL SAFETY PERFORMANCE

Bundle and Vendor Performance Year-To-Date

Period Ending: 30-Sep-16

SAFETY PERFORMANCE - YEAR TO DATE (YTD)

All Injury Rate (AIR)	Actual		Target	Status	Trend
Nuclear Refurbishment Program					
	Previous	Current			
OPG and Vendor Refurbishment Staff	(4) 0.24	0.55	0.24		↓

EXECUTIVE SUMMARY

Safety performance over the quarter has declined as a result of four medically treated injuries; one on the Turbine Generator pre-requisite project; and three within the Facilities & Infrastructure and Safety Improvement Opportunities projects. All injuries were minor in nature, and employees returned to work with zero lost days. Two High Maximum Reasonable Potential for Harm (MRPH) events occurred in the quarter on a Safety Improvement Opportunities Project.

# of Days Since a Lost Time Injury	2,464	Since Jan. 1, 2010

BUNDLE SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Line	Project Bundles (Additional Project Bundles will be added as they commence work on site.)	AIR	ASR	Safety Injuries			Safety Incidents			Hours Worked
		All Injury Rate	Accident Severity Rate	# Lost Time Injury	# Medical Injuries	# First Aid Injuries	# High MRPH	# Med. MRPH	# Level 1 Work Protection Events	
1	Re-tube & Feeder Replacement	[redacted]								
2	Turbine Generator									
3	Fuel Handling & Defueling									
4	Shutdown Lay-up									
5	Islanding									
6	Balance of Plant									
7	OPG Refurbishment Staff									
8	**Unit 2 Refurbishment Performance**									
9	Facilities & Infrastructure and Safety Improvement Opportunity Projects									
10	**Nuclear Refurbishment Performance**	**0.55**	**0.00**	**0**	**5**	**18**	**4**	**1**	**0**	**1,831,725**

VENDOR SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Excluding Owner-Only Metrics

Line	Vendors (Additional Vendors will be added as they commence work on site.)	AIR	ASR	Safety Injuries			Safety Incidents			Hours Worked
		All Injury Rate	Accident Severity Rate	# Lost Time Injury	# Medical Injuries	# First Aid Injuries	# High MRPH	# Med. MRPH	# Lvl 1 Work Protection Events	
1	[redacted]									
2										
3										

OWNER-ONLY SAFETY PERFORMANCE - YEAR TO DATE (YTD)

1	Refurbishment Project Office	0.00	0.00	0	0	0	0	0	0	11,718
2	Re-tube Waste Processing Building	2.54	0.00	0	2	0	0	0	0	157,485

EXPLANATORY NOTES

(1) A worker on the [redacted] was treated for an eye irritation, received eye drops, and returned to work. The vendor has upgraded eye protection requirements as a result of the incident.

(2) Three medically treated injuries occurred over the quarter, and an additional one in June. A worker on the [redacted] twisted his arm; a worker on the [redacted] cut his finger; a worker on the [redacted] bumped his head, and another cut his forehead. All employees returned to work for their next scheduled shift with no lost time.

(3) Two High Maximum Reasonable Potential for Harm (MRPH) events occurred in the quarter on the [redacted] for a total of three High MRPH events year-to-date. The first occurred while lifting the exhaust stack into the upright position. A sling broke causing the lower end of the stack to drop approximately three feet. There were no injuries as a result of this incident, and corrective actions have been taken to prevent re-occurrence. The second incident occurred when a worker unknowingly accessed an unapproved scaffold, exposing himself to a height greater than three meters. In both incidents, performance management was performed by the vendor, which resulted in suspensions and terminations primarily for the trades supervision on these projects.

(4) The previous All Injury Rate Reported has been adjusted to account for a first aid injury that occurred in June which was reclassified to a medically treated injury, impacting the All Injury Rate.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 11: QUALITY PERFORMANCE

Bundle and Vendor Performance Year-To-Date

Period Ending: 30-Sep-2016

QUALITY PERFORMANCE - YEAR TO DATE (YTD)

Overall Quality Performance	Status		Trend	Days Since Last Q-EFDR
Nuclear Refurbishment Program				
	Previous	Current		
				None YTD

EXECUTIVE SUMMARY

The overall quality performance has improved to white over the quarter since there were no significant quality issues identified by OPG or Vendors in the period. The Quality Performance report has been enhanced to reflect the year-to-date performance as opposed to the period, which is in alignment with safety performance reporting. Details on incidents over the quarter are detailed in the explanatory notes below.

BUNDLE QUALITY PERFORMANCE - YTD

Line	Bundles	*Quality Event Free Day Resets (Q-EFDR)*	*Regulatory Non-compliance Events*	*Non-conformance Corrective Action Requests*	*OPG Station Condition Records with Major Impact*	(4) *Rework (Execution)*	*Average # of revisions per closed-out Engineering Change*	*Comprehensive Work Package Non-compliances*	(5) *Work Plan Non-compliances*	(5) *Inspection & Test Plan Non-compliances*
1	Re-tube Feeder Replacement	[redacted]								
2	Turbine Generator									
3	Fuel Handling & Defueling									
4	Steam Generator									
5	Balance of Plant									
6	Refurbishment - Ops & Maintenance									
7	Refurbishment - Other Functions									
8	**Nuclear Refurbishment Performance**									
9	Facilities & Infrastructure and Safety Improvement Projects									
10	**Nuclear Refurbishment Performance**	**0**	(1) **1**	(2) **2**	(3) **4**	**0**	**1.6**	**41**	**18**	**37**

VENDOR QUALITY PERFORMANCE - YTD

Line	Vendors	*Quality Event Free Day Resets (Q-EFDR)*	*Regulatory Non-compliance Events*	*Non-conformance Corrective Action Requests*	*Vendor Corrective Action Requests*	*Rework (Execution)*	*Average # of revisions per closed-out Engineering Change*	*Comprehensive Work Package Non-compliances*	*Work Plan Non-compliances*	*Inspection & Test Plan Non-compliances*
1	[redacted]									
2										
3										
4										
5										

EXPLANATORY NOTES

(1) The regulatory non-compliance event is the previously reported issue related [redacted] quality control process and records on the [redacted] (a non-refurbishment project). However, the event is included in this report as it relates to a refurbishment vendor's quality process. Interim actions have been taken to prevent reoccurrence and corrective actions are in progress.

(2) There have been no new Non-conformance and Corrective Action Requests raised in the quarter. The two year-to-date events reflect the previously identified issue [redacted], and the [redacted] issue related to less than acceptable operational safety focus.

(3) One OPG Station Condition Record (SCR) with Major Impact was initiated over the quarter. The SCR documented the challenges to complete preparation of Comprehensive Work Packages, Work Plans and Inspection & Test Plans as per the plan. Corrective actions are in place to ensure all documentation is in place prior to the need date.

(4) The Rework (Execution) indicator has been added as a quality performance measure. It reflects the number of rework incidents that have an impact greater than $100K, or delay on critical path greater than six hours. There have been no execution rework events year-to-date.

(5) Non-significant non-compliances for Comprehensive Work Packages, Work Plans and Inspection & Test Plans are tracked for trending purposes.

ONTARIO POWER GENERATION

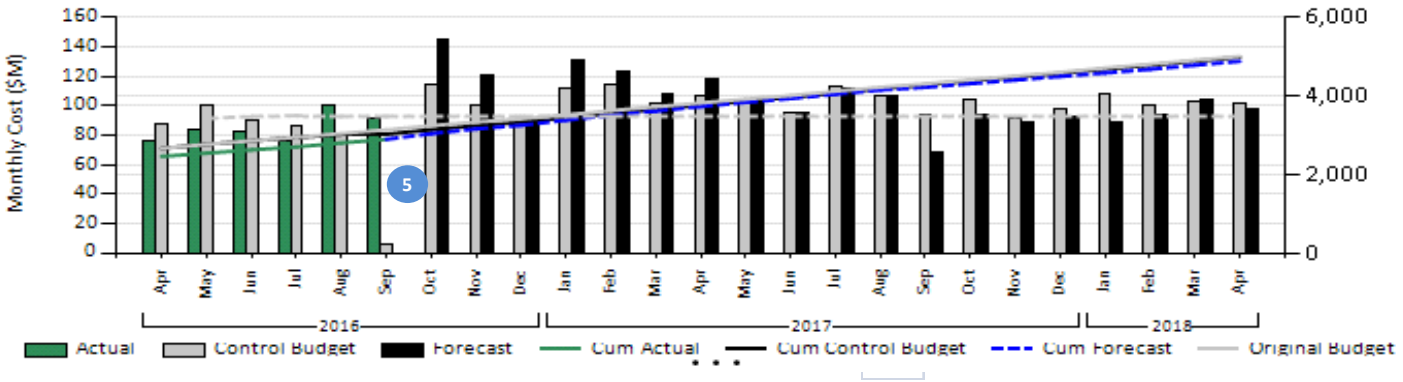
Darlington Nuclear Refurbishment Program

APPENDIX 12: PROGRAM FINANCIAL PERFORMANCE

Cost Performance of the Program Against Plan

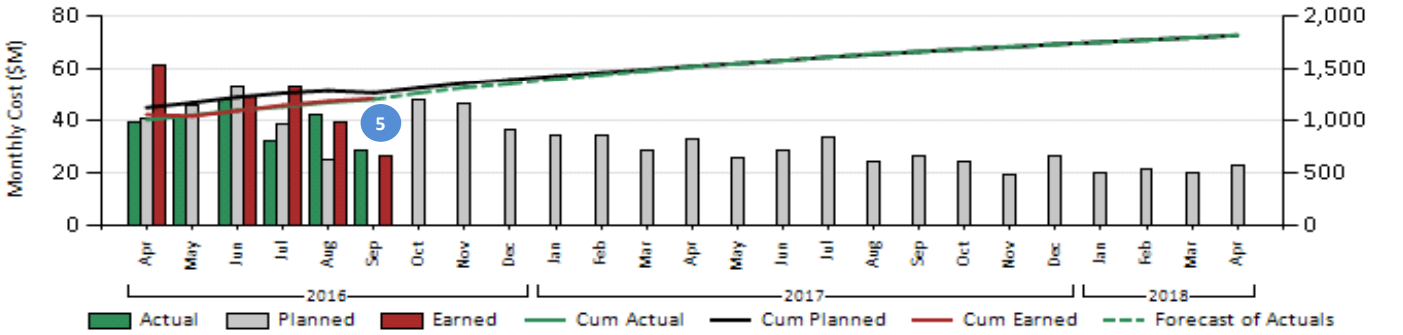
Period Ending: 30-Sep-2016

LIFE-TO-DATE COST PERFORMANCE FOR THE PROGRAM



Life-To-Date	
Original Budget	1 3,143,801
Control Budget	3,032,799
Actual	2,900,320
Variance-to-Control Budget	2 (132,479)
% of Control Budget Spent	96%

LIFE-TO-DATE EARNED VALUE FOR THE PROGRAM



Life-To-Date	
Planned Value	1,258,903
Earned Value	1,205,350
Actual	1,196,114
Variance-to-Planned Value	(62,789)
Cost Performance Index	3 1.01
Schedule Performance Index	4 0.96

EXPLANATORY NOTES

1. The original budget reflects the high confidence Release Quality Estimate approved by the Board of Directors in November 2015. The control budget is the approved plan that performance is measured against, and which currently reflects the revised Unit 2 cost established on September 30.
2. Life-to-date cost variance is $133 Million below plan, $29 Million attributable to lower than planned OPG resources, and $104 Million due to the timing of planned work, specifically:
   i) $28 Million underspend within the Facilities & Infrastructure and Safety Improvement Opportunities projects,
   ii) $25 Million underspend in planning and procurement activities for the subsequent units, largely within the Re-tube & Feeder Replacement project; and
   iii) $38 Million on Re-tube & Waste Processing Building project, and $13 Million underspend on the remaining core projects.
3. CPI has declined slightly to 1.01; however, continues to indicate that the work performed has been completed for less than originally budgeted. These efficiencies are largely due to fewer resources required to perform the work or lower vendor costs.
4. Schedule performance measured against the working schedule, has improved over the period at 0.96 as a result of the alignment of the Unit 2 schedule and cost baseline issued on September 30. The program remains slightly behind plan as a result of delays in completing the F&IP and SIO projects, and the Unit 2 pre-requisite projects.
5. The reduced plan within September 2016 is an artifact of the schedule and cost alignment that occurred on September 30.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

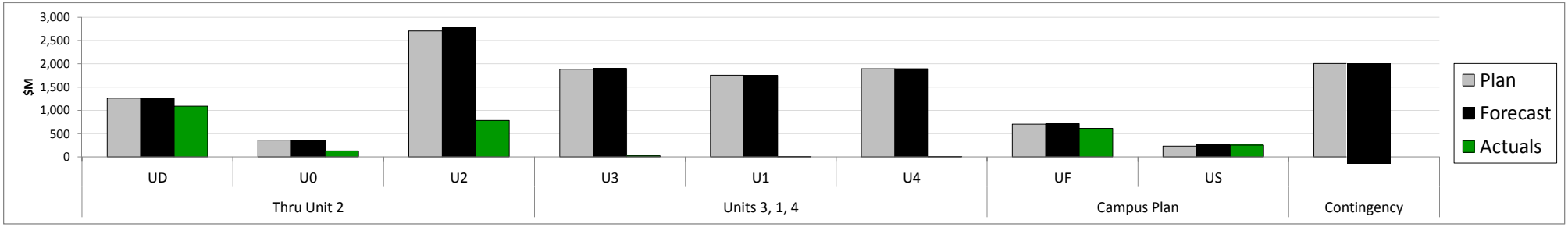
APPENDIX 13: PROGRAM FINANCIAL PERFORMANCE BY UNIT

Financial status of the Program by Unit

Period Ending: 30-Sep-2016

		Cumulative (Life-To-Date)					At Completion of Program		
		a	b	c = b - a	d	e	f	g	h = f + g
Line #	Description	Plan (PV)	Actual (AC)	Cost Variance	CPI	SPI	Plan	Life-to-date Actual Contingency Drawdown	Forecast
	Unit D - Definition Phase Work	1,086	1,092	6	0.99	1.01	1,262	[redacted]	[redacted]
	Unit 0 or Unit Common	173	129	(44)	1.38	0.83	361		
	Unit 2	846	785	(62)	1.06	1.03	2,704		
	Thru Unit 2	**2,105**	**2,006**	**(99)**	**1.05**	**1.00**	**4,326**		
	Unit 3	40	26	(14)	1.21	0.81	1,884		
	Unit 1	6	0	(6)	-	-	1,756		
	Unit 4	5	0	(5)	-	-	1,895		
	Units 3, 1, 4	**51**	**26**	**(25)**	**1.21**	**0.65**	**5,535**		
	Unit F - Facilities & Infrastructure Projects Work	658	616	(43)	0.93	0.84	702		
	Unit S - Safety Improvement Opportunity Work	237	252	15	0.89	0.98	230		
	Campus Plan	**895**	**868**	**(28)**	**0.91**	**0.89**	**933**		
	Contingency						2,006		
	Total	3,033	1 2,900	(133)	1.01	0.96	12,800	0	2 12,800

Note: - CPI and SPI are calculated on Deliverable Based work packages only.
- All Values Include Interest and Escalation



EXPLANATORY NOTES

1. Actual cost to date is $2.9 Billion, $133 Million under spent; $28 Million in Facilities & Infrastructure due to delays in completing planned work; $99 Million through Unit 2 due to lower than planned resources, and rescheduling of planned work; and $25 Million for planning and procurement for subsequent units.
2. 4-Unit cost estimate remains within $12.8 Billion.
3. Total contingency drawdowns, as per Appendix 14, is [redacted]

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

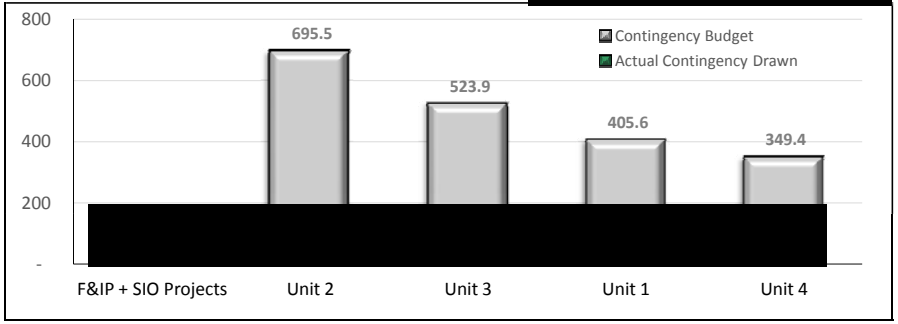
APPENDIX 14: PROGRAM CONTINGENCY MANAGEMENT

Financial Status of the Program Contingency by Unit

Period Ending: 30-Sep-2016

CONTINGENCY DRAWDOWNS BY UNIT AGAINST TOTAL PROGRAM BUDGET

Line #	Unit	Contingency Budget	LTD Actual Contingency Drawdown	Remaining Contingency	% Drawn
1	UF/US - F&IP & SIO Projects	31.9	[redacted]		
3	U2 - Unit 2	695.5			
4	U3 - Unit 3	523.9			
5	U1 - Unit 1	405.6			
6	U4 - Unit 4	349.4			
	Total	(1) **2,006.3**			



EXECUTIVE DISCUSSION

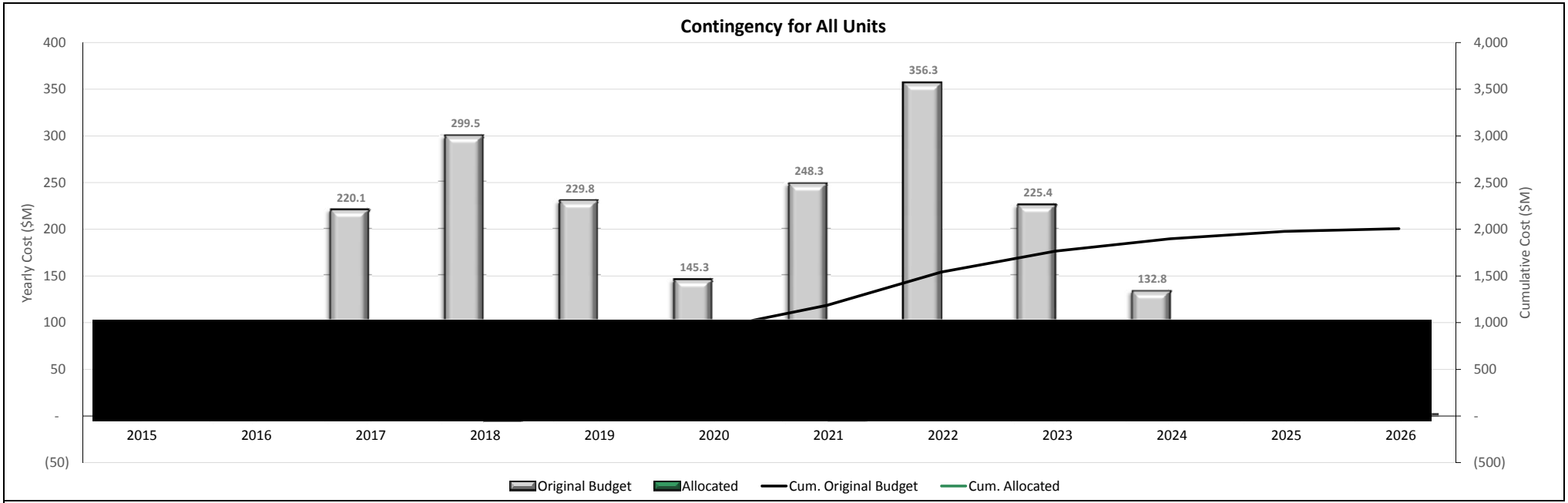
(1) The contingency budget for each unit is aligned with the $2,006 Million of contingency reported in the Unit 2 Execution Estimate provided to the Board in August 2016.

(2) The current contingency allocation for the 4-unit refurbishment is [redacted] (also shown in Appendix 13) of which [redacted] is for Facilities & Infrastructure (F&IP) and Safety Improvement (SIO) projects; [redacted] is for the Unit 2 projects and [redacted] is for subsequent unit work. Note: [redacted] was drawn from Unit 2 contingency to fund a SIO project, and is reflected in both Appendix 13 and 14.

Over the quarter, [redacted] of contingency was allocated to the projects through the change control process; [redacted] to the Facilities & Infrastructure and Safety Improvement projects; [redacted] to the Unit 2 projects; and [redacted] to future unit project work.

CONTINGENCY DRAWS DURING THIS PERIOD

(3) Contingency draws during the period are largely due to the Balance of Plant bundle, specifically the drying of the Primary Heat Transport Auxiliary System dead legs which is a result of refinement in the scope. Further drawdowns are attributed to cost overruns on the Containment Filtered Venting System project and changes in contracting strategies within the DRP.



ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - F&IP and SIO

APPENDIX 15: FACILITIES & INFRASTRUCTURE AND SAFETY IMPROVEMENT OPPORTUNITIES PROJECTS

Cost and Schedule Performance

Period Ending: 30-Sep-2016

COST DETAIL ($ MILLION)

		Cumulative (Life-to-Date)					At Completion of Project				In-Service Date			
		a	b	c=b-a	d	e	f	g	h	j	k	m	n	o
Line	Project Title	Plan (PV)	Actual (AC)	Variance	CPI	SPI	Original Budget (OB)	Estimate at Completion (EAC)	Variance from Original Budget	Variance from Last Period	Need Date	Current Forecast	# Months Float	Variance from Last Period
1	Heavy Water Storage & Drum Handling Facility	332.3	296.7	(35.6)	0.93	0.84	381.2	1 381.1	(0.0)	0.0		May 2017	0	0
2	3rd Emergency Power Generator	117.2	124.7	7.5	0.87	0.96	115.0	2 132.9	17.9	3.9	Mar 2017	Dec 2016	3	2
3	Containment Filtered Venting System	80.0	88.7	8.6	0.90	1.00	80.6	3 94.0	13.4	5.0	Dec 2016	Nov 2016	1	2
4	Shield Tank Over Pressure Protection	19.3	19.2	(0.0)	0.90	1.01	14.1	4 32.7	18.6	1.6	U1-D1711 U2-DNRU2	U1-D1711 U2-DNRU2	0	N/A
5	Balance of Pre-Requisite Projects In-Service	337.3	326.2	(11.1)	*	*	327.1	328.2	1.0	(3.9)	IN SERVICE			
6	**Subtotal Campus Plan Before Contingency**	**886.2**	**855.6**	**(30.6)**	**0.89**	**0.81**	**918.0**	**968.9**	**50.9**	**6.6**				
	Project Contingency (included)	*	*	0.0	*	*	[redacted]							
7	**Program Contingency**	*	*	*	*	*								
8	**Total Campus Plan including Contingency**	**886.2**	**855.6**	**(30.6)**	*	*								
Portion of the Re-tube & Feeder Replacement Bundle														
9	Re-tube Waste Processing Building	127.1	89.5	(37.6)	1.43	0.84	192.0	193.4	1.4	2.5	Jul 2017	Jun 2017	1	0

Notes: * Indicates not applicable. The CPI and SPI calculations exclude project management costs and support tasks which are considered level of effort. PHT = Primary Heat Transport

EXECUTIVE DISCUSSION

1. There is a risk that the cost to complete the facility will increase. OPG is currently negotiating with the vendor to resolve irregularities in the estimate and agree to any required change orders. At that time, the estimate will be evaluated. The final in-service date for the Heavy Water Storage Facility has been maintained since the previous report. Contingency measures for temporary heavy water storage utilizing existing station facilities have been developed to mitigate potential impacts of a delayed in-service on the Unit 2 execution schedule.
2. The estimate to complete the project has increased since the last report as a result of delays in construction, and additional commissioning costs. As previously identified, due to the complexities of the commissioning process and site integration, the in-service date of the 3rd EPG has been delayed to December 15 with remaining risks. The IIP Change Control Process was initiated, and the CNSC has accepted a change to the regulatory commitment, with a revised need date of March 2017.
3. The estimate to complete the project has increased since the last report as a result of delays in construction and additional commissioning costs. The in-service date is November 30. The IIP Change Control Process was initiated, and the CNSC has accepted a change to the regulatory commitment, with a revised need date of December 2016.
4. The forecast to complete the installation of the STOP modification on all four units is $32.7 Million; however, $16.1 Million represents the cost to rectify a pre-existing system condition, and address design changes to the system. Of $16.1 Million, [redacted] in contingency has been drawn down from the Unit 2 program contingency. As previously identified, the remaining [redacted] was under assessment for funding by the Nuclear Projects Portfolio. This assessment concluded that the additional cost is to be funded by Refurbishment contingency. The STOP modification and system design changes were installed and successfully tested on Unit 3 during the fall station outage. Unit 1 STOP modification and system correction is planned for the next Unit 1 outage in spring 2017. This outage has been rescheduled to occur after the Unit 2 Bulkhead installation to minimize interferences.
5. A total of [redacted] of additional contingency, above the contingency allocated during the Release Quality Estimate, is required to complete the projects based on the current estimates. Of the [redacted], [redacted] related to the additional STOP scope to rectify the pre-existing system condition as discussed in Note 4 above. Additional details on contingency use are contained in Appendix 14 - Contingency Management.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 16: KEY PROGRAM RISKS

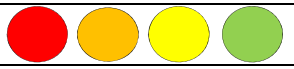
Risks Being Actively Managed by the Program

Period Ending: 30-Sep-2016

KEY PROGRAM RISKS AND MITIGATION STATUS

Line	Status	Risk Description	Mitigation Plan
1	-	**Vendor Performance** Poor vendor performance will negatively impact safety, quality, cost and/or schedule.	Vendor Performance continues to challenge the Refurbishment program. Plans to improve collaborative activities with the vendors for Engineering, Procurement and Construction have been developed and are in progress. This includes active management and assisting vendors in removing barriers to work. The Nuclear Construction Supervisor Academy is operational and has processed many vendor supervisors with positive feedback and results to date. The academy is integral to improving vendor supervisory performance. A second set of integrated schedule reviews was conducted at offsite meetings in late June and yielded a number of opportunities to resolve issues prior to breaker open. Integrated resource plans are in place for RFR JV and ES Fox; resource plans have been reviewed and accepted by OPG for various projects. Integrated field readiness walk downs at T-6 months and T-3 months with refurbishment and vendor teams will also promote better vendor performance overall in the field portion of the work.
2	-	**Availability/Retention of Project Leadership** Key project personnel with the required skill set will not be in place for the full refurbishment program resulting in impacts on performance.	Focus remains on establishing a strategic resourcing framework for the project under the RQE approved budget with the right organizational design and ensuring the right leadership pipeline is in place for future unit refurbishments (Units 3, 1, 4). Phase 2 of the Nuclear Fleet Bench Strength Improvement Plan is in progress. The Simplified Hiring item on the Nuclear Refurbishment top 10 priority list have been completed, with the central resourcing team currently in place and single point of contacts assigned to support each organization in the expedition of staffing needs. The resource plans have been compared against RQE staffing forecasts to ensure alignment.
3	-	**Availability of Skilled Craft Resources/ Supervision** Key skilled craft resources may not be available when required for the Execution Phase.	Focus continues on the onboarding for trades workers and the New To Nuclear (NTN) program for Unit 2. OPG participates in labour market information studies to gain insights into labour market issues, including the identification of skilled craft resource needs using tactics that include both short and long term approaches. There is no significant risks perceived for Unit 2, however there is a risk to future units with the start of the Bruce Power Major Component Replacement program in 2019. Discussions and collaboration with Bruce Power continue and it is expected this risk will be mitigated. The current plans and tactics are being evaluated to ensure integration with the Nuclear fleet to minimize the risks in all support areas. Provisions in trades union agreements also provide for resourcing flexibility, all major unions signed Nuclear Project Agreement (NPA).
4	↑	**First of A Kind/First in A While Work and Processes** A lack of recognition of FOAK/FIAW work and processes during design and execution planning results in installations that do not meet requirements causing rework/delay or degraded production post Refurbishment.	A thorough and in-depth review was completed with Engineering, project teams and various execution and functional groups in the Nuclear Refurbishment and Projects & Modifications organizations to flag FOAK/FIAW risks. A defined set of screening criteria to align with the WANO 2015 SOER report was developed and utilized. Specific mitigation actions are defined for FOAK/FIAW risks, and In-depth challenge/review of risks impact/events along with robust tracking of the mitigation actions are in progress. The initial listing of FOAK/FIAW work and processes review have been completed and this exercise will sustain throughout the refurbishment.

- No change over period
↑ Improvement
↓ Decline

HIGH RISK  LOW RISK

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 17: BUNDLE PERFORMANCE SUMMARY

Bundle Performance in the Four Pillars of Project Excellence -

Period Ending: 30-Sep-2016

BUNDLE PERFORMANCE INDICATORS

Line	Bundle Name	Safety (AIR)	Quality	Cost (CPI)	Schedule (SPI)	Explanatory Notes
1	**Re-tube & Feeder Replacement**	– 0.00	–	– 1.07	↑ 0.99	No safety issues have been identified. Cost performance has remained consistent and schedule performance has improved from 0.94.
2	**Balance of Plant**	– 0.00	↓	↑ 1.01	↑ 0.93	No safety issues have been identified; however, design deficiencies have resulted in numerous Field Initiated Changes and represents a legacy engineering quality issue. Schedule performance is 0.93 and is driven by delays in executing Unit 2 pre-requisite projects. Recovery plans are in place to mitigate the risk to the Unit 2 refurbishment execution schedule.
3	**Steam Generators**	– 0.00	–	– 1.05	↓ 0.89	No safety or quality events have been identified. Schedule performance has decreased due to delays in procurement activities caused by an addition to engineering and testing activities for required parts.
4	**Turbine Generators**	↓ 2.75	–	↑ 1.11	– 1.10	Safety performance has declined as a result of a medically-treated injury on the project. Cost performance and schedule performance are positive. Review is in progress to identify and incorporate lessons learned.
5	**Fuel Handling | Defueling**	– 0.00	–	↓ 0.98	↓ 0.91	No safety or quality events have been identified. Schedule performance has declined as a result of the Powertrack Project where the baseline is pending update to an optimized execution strategy. Baseline will be updated by end of November 2016.

Note: The CPI and SPI calculations exclude project management costs and support tasks which are considered level of effort.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 18: VENDOR PERFORMANCE SUMMARY

Vendor Performance - Core Refurbishment and Facilities & Infrastructure and Safety Improvement Projects

Period Ending: 30-Sep-2016

VENDOR PERFORMANCE INDICATORS

Line	Vendor Name & Key Scope	Safety	Quality	Cost	Schedule	Relationship	Explanatory Notes
1	[redacted]						
2							
3							
4							
5							

Note: The CPI and SPI calculations exclude project management costs and support tasks which are considered level of effort. The Safety All Injury Rate (AIR) includes

Darlington Nuclear Refurbishment Program

APPENDIX 19: METRICS LEGEND

Period Ending: 30-Sep-2016

DARLINGTON REFURBISHMENT PROGRAM PERFORMANCE DASHBOARD

METRIC/DESCRIPTION	TARGET	Excellent	Good	Moderate	Poor	↑ – ↓
COST PERFORMANCE INDEX (CPI) Ratio that measures the financial effectiveness. **SCHEDULE PERFORMANCE INDEX (SPI)** Ratio of schedule efficiency to date.	1.00	1.01-1.05	1.06-1.09 0.95-1.00	>1.09 0.91-0.94	<0.91	Managements assessment on the current performance trend. ↑ Performance is IMPROVING – Performance is MAINTAINED ↓ Performance is DECLINING
ALL INJURY RATE (AIR) (# Safety Events/200k hrs worked) Safety events are categorized as the number of fatalities, lost-time injuries, medical treatment injuries and other injuries/illnesses. **The safety statistics include both OPG and contractor performance year-to-date (i.e. reset in January).**	0.24	AIR ≤0.10 AND WP Events = 0	AIR 0.11- 0.24 AND WP Events = 0	AIR 0.25-0.27 OR WP Event = 1	AIR >0.27 OR WP Event ≥2	
# LEVEL 1 WORK PROTECTION EVENTS Count of the number of Level 1 Work Protection Events on DRP over the quarter.	0	AIR is significantly below target AND zero Work Protection Events in the quarter	AIR is at or below target AND zero Work Protection Events in the quarter	AIR is above target within 10% OR 1 Work Protection Event occurred in the quarter	AIR is above target > 10% OR ≥2 high Work Protection Event occurred in the quarter	
# EVENT FREE DAY RESETS (EFDR) The number of Darlington Site Event Free Day Resets that occurred within the quarter as a direct result of work being performed within the Darlington Refurbishment Program. The criteria are aligned to the nuclear industry standards and applied consistently across the sites to allow performance comparisons and benchmarking.	0	BOTH at ZERO	BOTH at ZERO Cumulative # of events for the quarter is 0, however previous performance was moderate or poor OR management assessment on low level trending	EFDR + REG. = 1 Cumulative # of events for the quarter is 1. OR management assessment on low level trending	EFDR + REG. ≥ 2 Cumulative # of events for the quarter is greater than, or equal to 2 OR management assessment on low level trending	
# REGULATORY NON- COMPLIANCE The number of regulatory non-compliance events related to quality that have occurred within the quarter.	0					

FINANCIAL SUMMARY

CURRENT APPROVED RELEASE refers to the total budget of the last release approved by the Board of Directors. The last release was approved by the Board in November 2015, and was to complete the Mobilization Phase.
MOBILIZATION PHASE refers to the work completed Dec 31, 2015 (end of Definition Phase) to October 15, 2016 (Unit 2 Breaker Open).
TOTAL PROGRAM refers to the refurbishment of all 4-units.

METRIC/DESCRIPTION		Excellent	Good	Moderate	Poor	↑ – ↓
LIFE-TO-DATE COST (M$)		Management's assessment based on: Current cost performance; Estimate at Completion; and Contingency allocation.				Managements assessment on the current performance trend. ↑ Performance is IMPROVING – Performance is MAINTAINED ↓ Performance is DECLINING
ACTUAL	Total Program costs incurred to date against the Approved Release.					
PLAN	Planned Program costs to date for the Approved Release.					
VARIANCE	Variance of Actual to Plan. ($) indicates underspend vs. plan.					
AT COMPLETION OF MOBILIZATION PHASE						
FORECAST	Forecast of total Program costs at the end of Mobilization phase.					
PLAN	Planned Program costs at the end of Mobilization phase as per the Approved Release.					
VARIANCE	Variance of Forecast to Plan. ($) indicates underspend vs. plan.					

PROJECT PERFORMANCE INDICATORS AND TRENDS

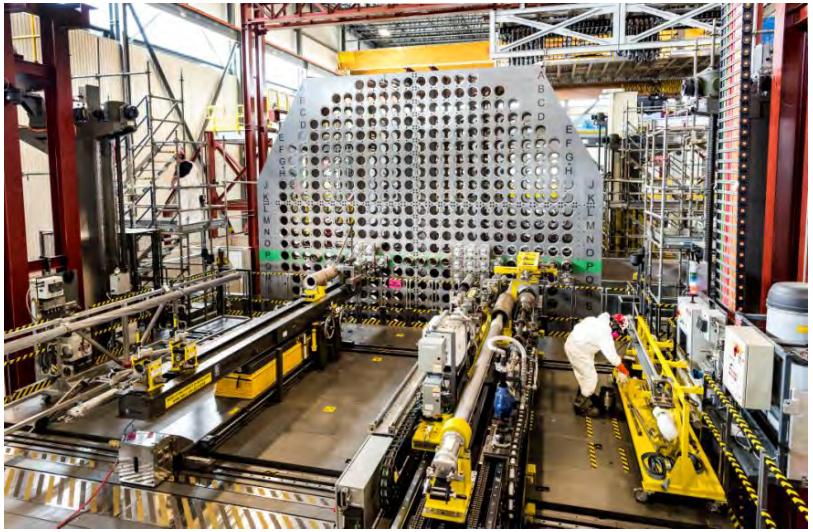
METRIC/DESCRIPTION	Excellent	Good	Moderate	Poor	↑ – ↓
UNIT 2 EXECUTION PROJECTS **PRE-REQUISITE PROJECTS**	Management's assessment of current performance and risk to Unit 2 Refurbishment Execution.				Managements assessment on the current performance trend.

APPENDIX 20: PHOTO CATALOGUE

Period Ending: 30-Sep-2016

PROJECT

Re-tube & Feeder Replacement



Reactor Mock-up

Heavy Water Storage & Drum Handling Facility

Erection of Structural Steel

APPENDIX 20: PHOTO CATALOGUE

Period Ending: 30-Sep-2016

PROJECT

3rd Emergency Power Generator

Completion of Civil Work

Stack Installed

Containment Filtered Vented System

Filter Enclosure

Filters Installed

APPENDIX 20: PHOTO CATALOGUE

Period Ending: 30-Sep-2016

PROJECT

Re-tube Waste Processing Building

Erection of Structural Steel

Re-tube Waste Storage Building
(non-Refurbishment funded)

Building Envelope

Installation of Lighting

UNDERTAKING J1.3

Undertaking

To produce the reports from the Refurbishment Construction Review Board from both the November-December visit and the February visit.

Response

The reports are provided in Attachments 1 and 2 (confidential).

Refurbishment Construction Review Board Review (November 29 through December 2, 2016)

Confidential (Commercially sensitive issues are discussed in this document)

Background:

The Refurbishment Construction Review Board (RCRB) conducted a review of the Darlington Refurbishment project from November 28 through December 2, 2016. This report is based on document reviews during the preparation for the review, interviews with Refurbishment personnel, plant walk-downs and observations during four days of the onsite visit.

The RCRB provides a report of its activities to the Senior Vice President Nuclear Projects which includes both observations and recommendations to improve performance. In addition to the report, a number of briefings to Senior OPG and Refurbishment Executives occurred on the RCRB findings.

The RCRB team consisted of the following members:

External members:

Ken Ellis (acting Chairman)
Drew Fetters
Britt McKinney
Ike Zeringue

Internal member:
Paul Pasquet

The RCRB would like to recognize the excellent support provided by Jennifer Vulanovic and Irena Doslo, their preparation and hard work enabled the RCRB to productively conduct this review.

The RCRB has made a limited number of key recommendations which the project needs to address with priority. The recommendations have been flagged and although no “formal” action plans are being requested, the RCRB will expect a formal briefing during the next visit to outline what actions have taken to address the identified issues.

Executive Summary:

The success of this project is in large part defined by the ability to achieve the published schedule. It is critical that the project leadership reinforce the need for Schedule Adherence which is not being adequately achieved at this point. Doing the right work, which starts on time, and finishes it on time with requisite Safety and Quality, must be the theme and content of management actions and communications. The Project leadership must focus their attention to ensure that both behaviours and results support this approach. This will require both an understanding of why the schedule is not adhered to and taking corrective actions to address the condition. The RCRB believes that field observation and coaching by the leadership team will assist in obtaining an understanding of the challenges and issues faced by field personnel.

Positive Observations

a) Fuel Handling Performance and Refurbishment based modifications to support Defueling of Unit 2

   Fuel Handling Performance (both fuel handing equipment and the staff) has been positive and event free. It has created the opportunity for the critical path to be advanced approximately 20 days from the base line schedule. This has been as a result of good collaboration between the Refurbishment team and the plant. The RCRB suggests making prompt decisions in advancing the schedule to take full advantage of schedule gains when they occur.

b) On boarding / Security Clearances / Recruitment

   Considerable progress has been made in recruiting the necessary people to support the project (approximately 200 people have been hired since staffing levels were reviewed in April by the RCRB). In addition there is good communication and prioritization of needs between the refurbishment staffing manager, security and the P&C (People and Culture) Recruitment team. The time to hire “current security cleared” augmented staff has been reduced to approximately 23 days. The overall On-boarding process is now more efficient. However a recent self-assessment has identified a number of program improvements associated with plant access and job specific training programs that should be implemented. These improvements have an owner and are progressing. The Refurbishment leadership team should continue to monitor the progress of these improvements.

c) Initial Islanding of the unit is adequate

The initial islanding efforts are viewed as achieving the initial goals of the project. The Unit 2 Refurbishment boundary points, perimeter barriers and ingress/egress routes have been established. The Islanding CBTs are relevant and raise general awareness of the unique conditions within the Refurbishment unit. It is expected that once all the Unit 2 systems required to support the operating units is finalized, additional work will be required to better refine the Unit 2 islanding requirements.

Recommendations and Key Observations

a) Work Execution

The RCRB considers the ability to execute the base line schedule the key issue that the project must address. Outlined below are a number of metrics which show the required volume of work which is not getting executed:

- Work week T-0 activity schedule completions are approximately 53% with a downward trend since breaker open.
- The activity work survival between T-2 and T-0 is approximately 50%.
- The project has completed approximately 55% of the scheduled activities when compared against the baseline schedule since breaker open.

In addition to this, a number of behaviours were noted that do not support completion of the approved schedule. Vendors are pulling non-scheduled work into the work week as opposed to adhering to the T-0 schedule. The RCRB observed that little effort is devoted to determining why schedule adherence is low, for example, why the work was not ready to execute. This is contributing to schedule adherence being well below target in the T-0 window. In addition, the SPI metric is providing an incomplete picture of schedule execution performance due to the amount of non-scheduled work that is being moved in the T-0 work weeks. At both schedule and metric review meetings the RCRB observed that the majority of the discussion was focused and making schedule changes to support execution shortfalls, versus what steps are being taken to adhere to the schedule. In addition, project management is not consistently holding the vendors to account for not adhering to the committed schedule.

Recommendation #1

(Note: The recommendation is very similar to the recommendation included in Appendix #1).

The RCRB recommends that action is taken to both understand why the desired task/work off rate is not being achieved and take the required actions to ensure this work is completed as scheduled.

The project currently carries out a "metrics / performance" review meeting but not a "T+1" type meeting to identify, understand and rectify the issues preventing the required work from being executed as scheduled. For example, in discussions with execution staff, it was apparent that for some work, the work instructions were handed to the craft during the execution week. This limits the ability to walk the work down and set the execution groups up for success. A detailed understanding of these challenges, along with corrective actions, is required in order to improve the schedule completion rate. Schedule adherence and the actions to improve performance needs to be a priority for the Leadership team.

b) Schedule Stability

There have been 540,692 hours added to the project and 278,238 hours removed for a net change of 262,454 hours since breaker open. Stated differently, 10% of the original U2 total hours has been added in the first 6 weeks. It is acknowledged a significant component of this issue was the one time inadvertent addition and removal of a large block of work. The fact this occurred supports the need for additional controls associated with changes to the schedule. Not only does this cause significant schedule 'churn', but these additions could impact project duration. Assuming the 20,000 hour per week work-off rate, if uncorrected, the extra 262,454 hours this represents 13 weeks of additional trades effort.

Based on meeting observations and a review of project metrics, there is a lack of controls associated with the vendors (and for OPG assigned work) adding hours to their projects or changing the start and finish dates to their work. It is strongly recommended that only OPG be authorized to make changes to the schedule. An example of a method (note, this is a suggestion only) to address schedule changes would be to first have the Project Manager review/accept/reject all recommended changes. These would then be forwarded to the Schedule Group, who would run them on the parallel schedule for impact. If the impact was not significant, they would be approved. If there was an impact to project duration or logic ties, then that change would be forwarded to the SVP of Refurbishment for approval. If approved, then the currently approved schedule would be updated.

Causes and Contributors

There are a number of improvements that can be made to improve project performance:

i. Transition to a more disciplined execution mode has not yet occurred (missed start and completion dates along with inconsistent demonstrated accountability by Project Managers and Vendors). Project Managers and Directors are not overtly driving their projects during project meetings. Work Management staff to their credit are attempting to fill the gap in this area.
ii. Some of the decision making is not being done in a manner which supports the project schedule. An example is a 'zero leakage' valve was specified for replacement in the Vault Vapor Recovery System (VVRS). A new technical specification called for "zero leakage" and the Vendor was attempting to purchase such a valve. It became apparent that a potential equivalent valve used in the same system was in inventory but did not have the "zero leakage" classification however no prompt decision making occurred to allow the work to proceed. As a result of this and other delays, this work has become near critical path.
iii. Time management within the project organization, which applies to OPG staff and the requirements OPG places on its Vendors, needs to transition to more of an 'execution focus.' Meetings need to be concise, focused on accountability and accomplishing work on time, along with being able to tactically and strategically look ahead. In addition, routine meetings are being used to make decisions. It appears there is an excessive number of meetings, many of which are attended by people who may be adding limited value.

Recommendation #2

The RCRB recommends that actions be taken to improve schedule stability.

i. As discussed above, controls need to be implemented to prevent unapproved or uncontrolled changes to the daily schedule or Level 1 schedule.
ii. In order to achieve schedule stability, the scheduled work needs to be ready to execute when required. For example, as discussed above, the quality of the work instructions are inconsistent and are being modified in the week before or week of execution. This limits the ability to walk down the work prior to execution. Consequently, there is a higher probability the work will be moved due to execution challenges. The project is attempting to get all work ready four weeks prior to execution. This is a notable goal

but may be difficult to achieve and will likely require incremental resources to achieve. The RCRB suggests the project ensure all work is ready two weeks prior to execution and ensure a graded approach to readiness prior to the work ready milestone (such as parts available/ engineering complete, etc.).

iii. The performance metrics associated with each Vendor and support group (OPG etc) is reviewed periodically to ensure they are playing their role in improving schedule stability.

iv. There are many different groups that need to play a role to support work execution. There needs to be a clear message that groups must support each other and when they do not, this needs to be identified to ensure the correct amount of support is obtained.

c) Tailored Project Reporting

A pyramidal system of metrics, scorecards and performance indicators is needed to effectively manage a project of this complexity. Quarterly reports of high level metrics and performance indicators are provided to the Board of Directors, and starting December monthly reports will be provided to the Board of Directors and the DRC (Darlington Refurbishment Review Committee). There is a large amount of lower level metrics generated, so much so that key trends may be lost in the volume. What is missing are the "aligned intermediate levels" between these two sets of metrics. As an example, "T-0" Schedule Completion and "T-2 to T-0" survivability should be selected as an intermediate level metrics. Another missing management tool is the absence of individual department "score cards" which drive both accountability and behaviour. It is acknowledged that work is underway in producing these intermediate levels. The absence of these intermediate level metrics and scorecards makes it difficult for the organization to manage the project.

Recommendation #3

(Reference recommendation #3, Appendix #1)

While the project does have a large number of metrics, they do not consistently provide a clear picture of project health for the project leadership. A "pyramidal system" of metrics, performance indicators, and individual department scorecards is needed to effectively manage a project of this complexity.

Other Observations

1. Sense of Urgency

The project needs to articulate and enforce what success looks like associated with accountability. Management behaviour when schedule expectations are missed requires improvement. The prevailing 'discussion' at meetings is focused on the new completion date , with little to no discussion as to why the original date was missed, nor does a healthy sense of urgency appear. In short, both the management team and the contract partners need to make it uncomfortable for those who do not deliver on their commitments, and offer support wherever they can to get the commitments back on track.

2. [redacted]

[redacted]

3. Valves

This is a 'critical activity' for the project. In the project, there are essentially two valve groups, one for valve replacements and one to perform periodic maintenance. The RCRB has yet to review the full scope of this work with all the owners. Project OPEX is that the valve program is the "Achilles heel" of most refurbishments and needs considerable oversight. The RCRB has yet to observe this and consequently this will be a focus area for a future RCRB visit.

4. Safety performance

Over a number of weeks prior to the review, several safety events have occurred at the DN site involving supplemental workers. During the review week a Station/Refurbishment stand down occurred to review these events with staff. In addition during the review week a significant work protection event and a serious personnel injury occurred. The RCRB noted during field tours a number of PPE non-compliances and a failure to tie off an impact wrench when working at heights. In our collective experience the main contributor for such performance is lack of communication and enforcement of expectations.

5. Monitoring of Boiler Chemistry

Since the unit was shutdown there have been challenges with boiler chemistry such as difficulties in maintaining chemistry within the administrative limits. Part of the issue appears to be after the installation of the boiler recirculating skid hoses which are adding sulphates to the boiler necessitating frequent boiler draining/refilling. During the morning meetings there was a lack of urgency to resolve the chemistry issue and it was the Outage director who spoke up to bring resolution to the issue versus someone from Operations/Maintenance. Based on PN RTS

operating experience, monitoring the boiler layup chemistry (and other system chemistry specs) was an issue and follow-up on chemistry issues needs to be closely monitored.

6. RTS group/Document closure

The project has formed a 'Closure Group' to ensure that all supporting paperwork is in order to support the efficient turnover of systems and equipment back to the Operating authority. The plan is comprehensive and relies on a computer program for tracking of key and supporting documents. This group is integrated into the Return to Service (RTS) function and is required to support the availability for service (AFS) process, prepare operations turnover plans and Level 2 Logic Diagrams, as well as review construction completion documents (CCD).

The Level 2 Logic Diagrams are a key aspect of RTS, and set the stage for the logic to return the plant equipment and systems to operation as well as setting up the closure process for success. These documents are targeted to be completed in June 2017. Efforts need to be expended to get these done as soon as possible in order to support the overall RTS process. The Level 2 Logic Diagrams efforts should be complete by now, but are not. These Level 2 logic diagrams will require operations review to ensure they are accurate. The RCRB is concerned with the availability of key operations personnel to manage getting work ready for execution, preparing commissioning plans, complete return to service activities and concurrently review the Level 2 logic diagrams.

7. Scaffolding

The Site should strongly consider the consolidation of scaffolding construction into a single group. This should eliminate variations in quality, avoidance of use by groups that did not build them, and aid in readiness for work, as well as removal when the work is complete. It should reduce the need for some scaffolding storage areas.

8. Project Effectiveness (Construction Switch)

The project has undertaken a number of initiatives to improve the efficiency of getting work executed. There are 16 different initiatives planned (in addition the vendors were asked to provide suggested efficiency improvement ideas). The plan has owner and target completion dates. To date a limited number of initiatives have been actually implemented. The focus areas appear to be appropriate but it is too early to assess progress on effectiveness of the program. This will need to be an ongoing initiative since the RCRB and the project staff believe opportunities to gain efficiency will continue to be identified as the Refurbishment project continues to ramp up its workforce and activities.

9. Field Services

The implementation of the field services engineering group is a recent initiative that is proving to be effective. Processes are flow charted, expectations are defined and metrics are in place. The field services group appears to be headed in the correct direction.

10. Presentation of Performance Metrics

The following are some suggestions on standardizing and improving the presentation of the metrics which are generated for the project;

- Each chart to have a legend which explains every bar colour and trend lines
- Each graph to have arrows indicating 1) Better than target or 2) Worse than target
- Each graph to have a box detailing the definition of metric
- Each graph to show the target performance
- Each graph to have a brief explanation as to what the current performance shortfall implications are (if applicable) and a few key corrective actions (who, what when) to address shortfall (if applicable)

Appendix 1

Recommendations from the July 18 - 22, 2016 RCRB Review

Recommendation #1

The RCRB recommends that action is taken to both understand why the desired task/work off rate is not being achieved and take the required actions to ensure this work is completed as scheduled.

This recommendation is still open

Recommendation #2

It is the RCRB experience that some form of "close out group" needs to be created to ensure that the close out of construction work is done correctly and timely. In addition a return to service group needs to expeditiously complete both the conceptual and detailed planning associated with returning of laid up / operating and modification systems and components to service. This activity needs to be monitored and tracked by the Refurbishment management team.

Progress has been made in addressing this recommendation. This recommendation will be reassessed during the next RCRB review.

Recommendation #3

While the project does have a large number of metrics, they do not consistently provide integrated picture of project health. The metrics identify individual project performance but do not adequate portray the integrated project execution and status. A "pyramidal system" of metrics and performance indicators is needed to effectively manage a project of this complexity. There are a sufficient number of metrics generated; they need to be strategically applied to allow management to focus on the problem areas.

This recommendation remains open. In this report the recommendation specifically targets a particular focus area for the project to address.

Recommendation # 4

With the reactor defueled and the unit separated from containment there exists an opportunity to enhance efficiency by streamlining various work processes so only those activities that truly add value (be it from a safety / quality / schedule or cost perspective) are in effect.

Progress has been made in addressing this recommendation. This recommendation will be reassessed during the next RCRB review.

Recommendation # 5

The level of accountability and understanding of what accountability means needs to be improved on the project. This includes a common understanding by both OPG and the contract partners of what it means to by an accountable organization. The RCRB is not suggesting that a management style be implemented that is inconsistent with the culture of OPG. For a project with multiple contractors, a number of different types of contacts and a large number of interface points between OPG and its Vendors, it is very important that all people involved are truly ready to execute their work as scheduled.

This recommendation is still open. There are pockets where the behaviours have improved but the results (example schedule adherence) are not at a point where this recommendation can be closed.

Refurbishment Construction Review Board Review (February 6-7, 2017)
Confidential

Background:

The Refurbishment Construction Review Board (RCRB) conducted a brief follow-up assessment of the Darlington Refurbishment project on February 6th and 7th 2017. The intent of this assessment was to status the implementation of the recommendations from the previous RCRB report. The RCRB provides a report of its activities to the Senior Vice President Nuclear Projects which includes both observations and recommendations to improve performance

The RCRB team consisted of the following members:

External members:
Ken Ellis (acting Chairman)
Drew Fetters (unable to participate in this assessment)
Britt McKinney
Ike Zeringue
Internal member:
Paul Pasquet

The RCRB would like to recognize the support provided by Irena Doslo.

Outlined below the RCRB has commented on the status of recommendations made in the previous report. The RCRB will expect a formal briefing during the next visit to outline the progress made to address the issues identified in this review.

Recommendations made in the previous RCRB review:

Recommendation #1

The RCRB recommends that action is taken to both understand why the desired task/work off rate is not being achieved and take the required actions to ensure work is completed as scheduled. Schedule adherence and the actions to improve this performance needs to be a priority for the Leadership team.

Recommendation #2

The RCRB recommends that actions be taken to improve schedule stability. In order to achieve schedule stability, the scheduled work needs to be ready to execute when required.

Recommendation #3

While the project does have a large number of metrics, they do not consistently provide a clear picture of project health for the project leadership. A "pyramidal system" of metrics, performance indicators, and individual department scorecards is needed to effectively manage a project of this complexity.

Recommendation Status

1. The project's most important focus area remains to improve schedule compliance at T-0 which includes completing the required work that supports the project schedule. As it currently exists today, the project is starting to build a bow wave of work. In addition, the float associated with a number of bundles of work is being used up, such that these bundles have the potential to impact the project's critical path.

   T-0 task completion as planned for the last 10 weeks is under 60%. Contributors to this issue are:
   a. The Weekly Performance Review Meeting (T+1) is not effective in identifying the reasons for not getting the work done, and in implementing the actions needed to improve performance. While this may be done on an intuitive basis, a rigorous approach has not been taken to implement corrective actions to address the issue.
   b. Work packages are not consistently ready to be worked at T-2, and sometimes at execution week. Package readiness is not being verified prior to being given to the craft on a consistent basis.
   c. Based on limited interviews, a common theme is parts are not being staged for the craft and work instructions are incomplete or inadequate.
   d. The RCRB recommends a dedicated effort focused on ensuring work packages can be implemented, where the general foreman verifies and signs off on the readiness. This may require augmented and/or dedicated resources.
   e. The RCRB recommends that an achievable but challenging yearend target for T-0 completion rate be set which includes interim targets. This will allow the organization to monitor and track performance improvement.

2. Scope Stability has improved from 25% to 40%. By having controls at T-2, there is a better opportunity for work package readiness to improve. We recommend that a future date be set to freeze scope at T-2, to allow the organization to prepare for this change.

Schedule compliance and stability need to be reflected in the Top 10 Refurbishment project priority list. This will provide visibility for the issue and allow staff to work to address the issue and see the progress being made.

Additional Observations:

1. A reconciliation was completed to address the changes in labour hours from Sept. 16 to Oct. 15. (Specifically identifying the cyclical outage work and AISC projects work which does not impact the total cost envelope of the project. This work will still need to be scheduled and monitored to ensure it does not have an impact on the project's schedule).

2. Some improvement has been noted in the refocus and accountabilities of the Project Manager. The RCRB was impressed by the Turbine Generator Project Manager's team and with the vendor relationship.

Other

[redacted]

UNDERTAKING J2.1

Undertaking

To advise how much of the $2.2 billion has already been approved by the Ontario Energy Board for recovery.

Response

Chart 1 presents the amounts for the Definition Phase of DRP that have been approved by the OEB. Years 2010 – 2014 are actuals that were approved through payment amounts applications EB-2010-0008 and EB-2013-0321 and trued-up through clearance of the Capacity Refurbishment Variance Account (CRVA) in EB-2012-0002 and EB-2014-0370. The amounts for 2015 are the amounts approved on a forecast basis in EB-2013-0321. OPG has proposed to clear amounts recorded in the CRVA in 2015 in this Application[1].

Chart 1 - Amounts for Definition Phase DRP Approved by the OEB

($M)	2010	2011	2012	2013	2014	2015
OM&A	3.2	2.2	2.8	6.3	6.3	18.2
Capital In-service	0	0	5.0	99.2	43.5	143.4[2]

[1] For 2015 amounts to be cleared in the CRVA, see Ex. H1-1-1 Table 11.
[2] Does not includes amounts for the Darlington Operations Support Building and Darlington Auxiliary Heating System projects that were approved and subsequently reclassified to the Nuclear Operations portfolio. As discussed in Ex. L-9.1-1 Staff-210 p. 3, lines 21-27, the revenue requirement of these forecast amounts was effectively credited back to customers through the CRVA, as a result of their reclassification.

UNDERTAKING J2.2

Undertaking

To provide P-level associated with the working schedule and cost level associated with the working schedule.

Response

The duration of the working schedule for Unit 2 is 35 months, as provided in L 4.3-2 AMPCO-066, p. 2, Chart 1. This working schedule duration is equivalent to a confidence level of P37 or 37%.

Completion of Unit 2 on the working schedule of 35 months, i.e. a return-to-service in mid-September 2019, would result in a reduction in the use of schedule contingency. OPG has approximated the reduction in the use of schedule contingency, based on the difference in durations between the P90 and the working schedule and an appropriate average daily rate.

OPG's estimates that the in-service amount associated Unit 2 based on the working schedule would be reduced by $144M, i.e. to approximately $4656M.

The working schedule is intended to be aggressive. OPG is managing the work to this schedule to allow early identification of risks so that mitigating action can be taken promptly.

UNDERTAKING J2.3

Undertaking

To determine the revenue-requirement impact of moving from a P90 to a P50 in this application.

Response

Please see Tr. Vol. 2, p. 202, lines 26-28, and p. 203, lines 1-6.

UNDERTAKING J2.4

Undertaking

To advise precisely where in the evidence there is an expert that says P90 is an appropriate allocation.

Response

The below references are derived from the Testimony of Dr. Patricia D. Galloway, located at Ex. D2-2-11, Attachment 3.

On page 8:

> "OPG's selection of a P90 confidence level for the Unit 2 schedule is reasonable and in accordance with the robust risk analyses that were performed."

On page 14:

> "By performing a detailed cost estimate and schedule based on a thorough and robust probabilistic risk assessment of the Program, *OPG has established a P90 confidence level of the cost to complete the Program and established an appropriate level of contingency, which in my opinion, is a reasonable cost estimate.*" *(emphasis added).*

On page 54:

> "Q. Did you assess whether the amount of contingency included in the RQE by OPG was reasonable given the nature of the DRP?
>
> A. *Yes. In review of the DRP documentation and through interviews with OPG personnel, I have determined that OPG's $1.7B of contingency for the DRP is reasonable*. I base this finding on my understanding of the robust method in which OPG determined its contingency amount, which included a comprehensive risk assessment, Monte Carlo simulations, vetting by internal and external parties, and the decision to use a P90 confidence level." *(emphasis added).*

On page 55:

"Q. Is it appropriate to use the P90 confidence level to determine the amount of contingency?

A. Yes. Although no specific confidence level is considered a best practice, using a P90 confidence level provides OPG with a high probability that the Program will be completed within the budget. Using a lower confidence level, such as a P50 confidence level, may not adequately address the complexities and risks inherent with the execution of a megaprogram (particularly the extended duration of execution as compared to a typical project), thus increasing the risk of a cost overrun."

On page 56:

"Q. Did you reach any overall opinions concerning the RQE $12.8B estimate for the DRP?

A. Yes. From my review and evaluation of the contemporaneous documentation and the interviews of OPG management, at the time the RQE cost estimate was completed, OPG had ample reason to feel confident in the accuracy of RQE estimate. I found the methodologies employed by OPG to develop the RQE estimate to be world-class. A review of all the relevant documentation and interviews with OPG project personnel confirmed the fact that the methodologies employed met all accepted industry standards and guidelines as promulgated by AACE. As I discussed earlier in my testimony, *the use of a P90 confidence level, along with the detailed estimate development process, provides OPG with appropriate assurances that the DRP can be completed within the $12.8B estimate.*" (*emphasis added*).

On page 62:

"Q. Do you believe it is reasonable to use the high-confidence P90 schedule for execution of Unit 2?

A. While there is no prescribed standard for use of a particular confidence schedule over another, OPG, by selecting the P90 schedule for Unit 2, has demonstrated its risk tolerance preference for a high-confidence schedule (aligning with its use of a P90 estimate) to limit the likelihood of schedule overruns. *I find OPG's selection of a P90 confidence level for the Unit 2 schedule to be reasonable and in accordance with the robust risk analyses that were performed.*" *(emphasis added).*

In part b of M1-4.3 AMPCO-009 regarding Schiff Hardin's assessment of whether a P50 versus a P90 contingency or another contingency probability is the industry standard, Schiff Hardin stated:

> "The P50 is an estimate of the project cost based on a 50% probability that the cost will not be exceeded. Stated another way, the P50 estimate is one with equal chance of project overruns or underruns. *The P90 is an estimate of the project cost based on a 90% probability that the cost will not be exceeded. Some project participants prefer to have less exposure to increases in capital budgets and often look for a P90 figure.* The P90 contingency means that the contingency allowance on top of the base estimate is sufficient to ensure that there is a 90% chance that the amount will not be exceeded. Budget determinations and the confidence level for projects/programs vary by the contracting strategy, schedule, and other project/program factors." *(emphasis added).*

UNDERTAKING J2.5

Undertaking

To advise whether the government was provided with a specific Unit 2 number in addition to the total DRP number.

Response

OPG did not provide a specific Unit 2 in-service amount to the Province when it obtained approval for DRP. A breakout of the total Darlington Refurbishment Program Estimate of $12.8B in terms of expenditures to date, future contract expenditures, future OPG expenditures, contingency and interest and escalation (similar to that shown in Ex. L 4.3-1 Staff-055 Attachment 1, p. 7) was provided to the Province.

UNDERTAKING J2.6

Undertaking

For Ex. D2-2-10, Tables 2 and Table 3, to provide updated final in service and cost information, and to provide 2016 actuals for projects that are in-service.

Response

Attachments 1 and 2 provide the actual or current forecast in-service date and cost information for the projects in Ex. D2-2-10 Tables 2 and 3, together with the Final In-Service Date and Total Project Cost information as originally filed.

Numbers may not add due to rounding.

Attachment 1
Updated Ex. D2-2-10 Table 2 per J2.6
Projects ≥ $20M Total Project Cost [1]

Line No.	Facility	Project Name	Project Number	Category	Start Date	Final In-Service Date (As Filed)	Forecast/Actual In-Service Date[4] (Updated)	Total Project Cost (As Filed) ($M)	Forecast/Actual In-Service Amount ($M)[4] (Updated)	Forecast/Actual OM&A Amount ($M)[4] (Updated)	Forecast/Actual Total Project Cost ($M)[4] (Updated)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k) = (i) + (j)
		ONGOING PROJECTS FROM EB-2013-0321									
1	DN	Darlington Refurbishment - Unit Refurbishment - Unit 2	Various	Unit Refurb - Unit 2	2010	Feb-20	Feb-20 (F)	4,800.2	4800.2 (F)	0.0 (F)	4800.2 (F)
2	DN	R&FR - Tooling for Removal Activities	73112	Unit Refurb - Early In-service	Feb-12	May-16	Jun-16 (A)	87.0	88.1 (A)	0.0 (A)	88.1 (A)
3	DN	Heavy Water Storage Facility [2]	31555	F&IP	Nov-06	May-17	TBD	381.1	TBD	TBD	TBD
4	DN	Water & Sewer Project [2]	73802	F&IP	Jun-10	Nov-15	Oct-14 (A)	57.7	44.8 (A)	3.3 (A)	48.1 (A)
5	DN	Darlington Energy Complex [2]	73803	F&IP	Mar-10	Jul-13	Jun-13 (A)	105.4	83.0 (A)	0.0 (A)	83.0 (A)
6	DN	Retube Feeder Replacement Island Support Annex [2]	73810	F&IP	Sep-11	Oct-15	Mar-16 (A)	40.7	45.3 (A)	0.4 (A)	45.7 (A)
7	DN	Refurbishment Project Office [2]	73815	F&IP	Sep-11	Jan-16	Sep-15 (A)	99.9	104.8 (A)	0.0 (A)	104.8 (A)
8	DN	Electrical Power Distribution System [2]	73821	F&IP	Nov-10	Oct-15	Jul-15 (A)	20.8	20.1 (A)	0.2 (A)	20.3 (A)
9	DN	Third Emergency Power Generator [3]	73360	SIO	Apr-12	Oct-16	Mar-17 (F)	120.4	139.6 (F)	0.4 (A)	140.0 (F)
10	DN	Containment Filtered Venting System [3]	73365	SIO	Aug-13	Aug-16	Mar-17 (F)	80.3	101.0 (F)	0.0 (F)	101.0 (F)

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period.
2 For F&IP, columns (f) and (h) reflect approved Business Case Summary.
3 For SIO, columns (f) and (h) reflect approved Gate Progression Form or Change Control Form.
4 Forecast (F) and Actual (A) as at December 31, 2016 as noted in columns (g), (i), (j) and (k).

Numbers may not add due to rounding.

Attachment 2
Updated Ex. D2-2-10 Table 3 per J2.6
Projects $5M - $20M Total Project Cost [1]

Line No.	Facility	Project Name	Project Number	Category	Project Description	Start Date	Final In-Service Date (As Filed)	Forecast/Actual In-Service Date[4] (Updated)	Total Project Cost (As Filed) ($M)	Forecast/Actual In-Service Amount ($M)[4] (Updated)	Forecast/Actual OM&A Amount ($M)[4] (Updated)	Forecast/Actual Total Project Cost ($M)[4] (Updated)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l) = (j) + (k)
		ONGOING PROJECTS FROM EB-2013-0321										
1	DN	Fuel Handling - IFB Heat Exchanger Plate Replacement	73164	Unit Refurb - Early In-service	Replace the plate packs for all 8 heat exchangers of the irradiated fuel bay system to restore cooling capacity and mitigate margin management issue	Mar-14	Jul-15	Jul-15 (A)	6.4	6.3 (A)	0.0 (A)	6.3 (A)
2	DN	Balance of Plant - Negative Pressure Containment	73471	Unit Refurb - Early In-service	Provide a redundant monitoring capability in Unit 3 for negative pressure containment parameters used in three safety related systems	Apr-12	Oct-16	Nov-16 (A)	5.1	5.7 (A)	0.0 (A)	5.7 (A)
3	DN	Balance of Plant - Heavy Water Islanding Modifications	73472	Unit Refurb - Early In-service	Provide isolation valves and a redundant pressure relief path for the headers used to transfer moderator and primary heat transport heavy water between units and the heavy water processing facility	Apr-12	Aug-16	Oct-16 (A)	5.6	10.6 (A)	0.0 (A)	10.6 (A)
4	DN	Balance of Plant - Low Pressure Service Water	73514	Unit Refurb - Unit 2	Re-orient a valve to allow a hose connection to be attached as part of the low pressure service water temporary modifications during Unit 2 refurbishment	Oct-14	Feb-18	Feb-20 (F)	6.4	5.3 (F)	0.0 (F)	5.3 (F)
5	DN	GM Facility Interim Office Leasehold Improvements [2]	73806 / 73814	F&IP	Make leasehold improvements for the Nuclear Refurbishment Interim Office Facility at 1908 Colonel Sam Drive "GM Facility" that will accommodate the Nuclear Refurbishment organization and some delegated support staff for the period between the fall of 2010 until the fall of 2013 when the Darlington Energy Complex is ready for use	Mar-10	Feb-20	Feb-20 (F)	9.3	10.2 (F)	0.0 (F)	10.2 (F)
6	DN	Vehicle Screening Facility [2]	73817	F&IP	Build an extension to the vehicle screening infrastructure at the DNGS Sally Port to increase throughput of vehicles entering/exiting the Darlington Protected Area at the Sally Port from the refurbishment and Campus Plan projects	Jun-13	Oct-14	Oct-14 (A)	6.6	6.5 (A)	0.1 (A)	0.1 (A)
7	DN	Powerhouse Steam Venting System Improvements [3]	73370	SIO	Increase nuclear safety margins by the addition of a second redundant control loop in the Powerhouse Steam Venting System initiation logic	Oct-12	Oct-15	Nov-15 (A)	5.6	5.7 (A)	0.0 (A)	5.7 (A)
8	DN	Shield Tank Overpressure Protection [3]	73380	SIO	Install relief devices to the Shield Tank Cooling System in each Darlington Unit to prevent shield tank failure from over-pressureization under Beyond Design Basis Accidents	Jan-13	Jul-17	Sep-17 (F)	13.5	32.7 (F)	0.0 (F)	32.7 (F)
9	DN	Emergency Service Water Buried Services [3]	73398	SIO	Replace the buried Emergency Service Water Piping L6 due to extensive corrosive pitting observed during inspection	Jul-13	Nov-15	Oct-15 (A)	14.6	13.9 (A)	0.0 (A)	13.9 (A)

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period.
2 For F&IP, columns (g) and (i) reflect approved Business Case Summary.
3 For SIO, columns (g) and (i) reflect approved Gate Progression Form or Change Control Form.
4 Forecast (F) and Actual (A) as at December 31, 2016 as noted in columns (h), (j), (k) and (l).

UNDERTAKING J2.7

Undertaking

Reference: Ex. D2-2-2, Attachment 2, p.21

To provide the major scope changes from when scope was finalized to present and any associated cost from these changes.

Response

There have been no major scope changes since the finalization of the approval of the Release Quality Estimate in November 2015 to the end of January 2017. Please refer to Ex. L-4.3-2 AMPCO-060 which indicates that since RQE to August 1, 2016, the number of Darlington Scope Requests had increased from 340 to 344, with no material impacts on cost and schedule. OPG confirms that since August 1, 2016, there have been no further material changes in scope and the number of DSRs remains at 344.

UNDERTAKING J2.8

Undertaking

To advise where the hockey stick curve (S-curve) for DRP contingency is in the evidence.

Response

OPG did not provide the S-curve at RQE in its pre-filed evidence, interrogatory responses or undertaking responses.

However, OPG did provide the following values associated with different confidence levels in responses to interrogatories L-4.3-2 AMPCO-70 and L-4.3-15 SEC-27. The values are reproduced below for ease of reference:

Chart 1 –
Confidence Level Values Provided in
L-4.3-2 AMPCO-70 and L-4.3-15 SEC-27

Reference Confidence Level	Total DRP Contingency Estimate at Reference Confidence Level (2015$B)
P10	1.2
P50	1.4
P70	1.53
P75	1.57
P80	1.61
P85	1.66
P90	1.71
P95	1.84
P99	2.60

UNDERTAKING J2.9

Undertaking

Provide list of major projects (or references) that will be put into rates effective 2020, that is beyond the Unit 2 refurbishment (same level of detail as provided in D2-2-5, p. 6).

Response

This response provides a list of projects that are common to two or more units that are proposed to close to rate base with Unit 2, as well as the rationale for why each project is included in the Unit 2 in-service addition.

Projects with a total cost exceeding $5M expected to be placed in service and proposed to close to rate base prior to the return to service of Unit 2 are set out in Ex. D2-2-10 Tables 2 and 3. These projects include Unit Refurbishment Early In-Service projects, Facilities & Infrastructure projects and Safety Improvement Opportunities, which, once completed, will immediately become used or useful to OPG's current nuclear operations, ahead of the completion of the Unit 2 refurbishment. These projects are discussed in Ex. D2-2-10, sections 2.2, 2.3 and 2.4, respectively. Placing these projects in service at the time of their completion is in accordance with US generally accepted accounting principles.

Chart 1 sets out the projects that are common to two or more units that are proposed to close to rate base with Unit 2, at which point these projects will become used or useful. These projects will be used or useful at the time Unit 2 is returned to service because they are necessary, in full, for the Unit 2 refurbishment, notwithstanding that their completion also may be necessary for the refurbishment of certain subsequent units. Placing these projects in service at the same time as Unit 2 is in accordance with US generally accepted accounting principles. In order to limit the number of projects to a reasonable number, a total project cost threshold of $5M was applied.

Chart 1: Projects Greater than $5M to be placed In-Service with Unit 2

Project Name	Rationale for Placing In-Service with Unit 2
Reactor Mock Up	Used for tool performance testing and verification and personnel training for the retube and feeder replacement activities, which are necessary to refurbish Unit 2, as well as subsequent units.

Project Name	**Rationale for Placing In-Service with Unit 2**
Tooling for RFR	Toolsets used for the retube and feeder replacement activities, which are necessary to refurbish Unit 2, as well as subsequent units. Consumables (e.g. lubricants, blade sets, etc) and maintenance on the tools used for subsequent unit refurbishments are charged to subsequent units.
Fuel Handling Powertrack Refurbishment	The Fuel Handling Powertrack is common to all units and will be refurbished during the Unit 2 refurbishment in order to ensure high performance during the post-refurbishment life of the units. Any remaining work on the Powertrack scheduled to be completed after Unit 2 returns to service will be placed in service with subsequent units.
Retube Waste Processing Building	Facility required to process Unit 2 retube waste (feeder pipes, pressure tubes, calandria tubes, end fittings, etc) and also for subsequent unit refurbishment waste processing.
Defueling (Engineering & Procurement)	This work pertains to engineering and procurement for defueling (execution of defueling is common to all units, but there will be no additional engineering scope for the remainder of the units).
Work Control Area	The work control area is required and used for the Unit 2 refurbishment, and will also be utilized during subsequent unit refurbishments.
Breathing Air Capacity Enhancement	Refurbishment of Unit 2 requires a high number of workers in radiation protection clothing (i.e. plastic suits) accessing breathing air. This required an upgrade to the station's breathing air system. The entire upgrade is necessary to execute Unit 2 refurbishment and will also be used during the subsequent unit refurbishments.
Service Air Capacity Enhancement	Refurbishment of Unit 2 required capacity enhancements to service air (e.g. for powering pneumatic tools). The entire upgrade is used to execute Unit 2 refurbishment and will be useful to the refurbishment of subsequent units.

Project Name	**Rationale for Placing In-Service with Unit 2**
*Radiation Protection & Teledosimetry Facility	Facility required and used for Unit 2 refurbishment, with utility to both Units 1 and 2.
*Decontamination Shops and Scaffold Storage	Facilities required and used for Unit 2 refurbishment, with utility to both Units 1 and 2.
*Shops and Work Areas	Facilities required and used for Unit 2, with utility to both Units 1 and 2.

* These three projects will be of utility to both Units 2 and 1. There will be a repeat of these three projects for Units 3 and 4. The costs of the repeat projects will be placed in-service with Unit 3.

UNDERTAKING J2.10

Undertaking

To provide the March quarterly management report to DRC and the Burns & McDonnell/Modus report once it has been issued to the OPG Board of Directors and subject to any confidentiality and disclosure concerns.

Response

Please see Attachment 1 for the management report to the Darlington Refurbishment Committee dated March 9, 2017 (confidential), and Attachment 2 for the Burns & McDonnell/Modus Independent Oversight Report dated March 2017 (confidential).

OPG Confidential Exclusive

ONTARIO POWER GENERATION

FOR INFORMATION to the Darlington Refurbishment Committee

March 9, 2017

DARLINGTON REFURBISHMENT PROGRAM

REASON FOR REPORT

This report provides the current status of the Darlington Refurbishment Program (DRP) including a review of strategic initiatives and program performance highlights for the quarter ending December 31st, 2016. This report augments the monthly Unit 2 Execution Status Report.

HIGHLIGHTS AND CONCLUSIONS

The execution of Unit 2 commenced on October 15th, 2016 as planned. Key program highlights for the quarter ending December 31st are listed below.

- At year-end, the combined OPG and contractor All Injury Rate (AIR) was 0.50 against a target of 0.24. There have been no lost time injuries.
- One quality incident occurred in the period associated with delays in placing SHIM mode operation in-service. SHIM mode operation is now in-service on all four Darlington Units and was utilised as planned on Unit 1 to support Unit 2 Refurbishment critical path.
- Defueling was completed on January 11th, 26 days ahead of the working schedule and 39 days ahead of the high confidence schedule. As a result, 13 days of schedule contingency valued at [redacted] has been returned to the Program General Reserve.
- Since the completion of defueling, the project has transitioned to vault preparations. As of end of February, due to unanticipated work, vendor performance, and vendor and OPG integration issues, the schedule gains achieved during Defueling have been consumed. Management anticipates that Segment 1 will be complete on March 30th, as per the original working schedule commitment.
- Some Unit 2 non-critical path activities are behind the working schedule and are impacting the Schedule Performance Index (SPI). Recovery plans have been implemented, and schedule performance of ES Fox work has greatly improved. Weekly performance monitoring is in place to ensure appropriate focus is placed on all activities to avoid impacts on critical path.
- The targeted 2016 in-service dates for the 3rd Emergency Power Generator (3rd EPG) and the Containment Filter Venting System (CFVS) projects were not achieved and this impacted the 2016 Corporate Scorecard results. Both projects are progressing through commissioning and are forecast to be placed in service mid-March.
- The DRP work completed to date has been performed for slightly more than budgeted, as reflected in the overall program Cost Performance Index (CPI) of 0.97, however, the program is holding adequate contingency for these variances. Life-to-date spending is $3.2 Billion, $79 Million below plan mainly due to lower than planned OPG resources and schedule delays.
- At the closure of 2016, 46 of 47 Integrated Implementation Plan (IIP) tasks committed to the Canadian Nuclear Safety Committee (CNSC) were completed. A late request has been approved by the CNSC to extend the CFVS in-service commitment from December 31st to April 28th, 2017. OPG continues to demonstrate to the regulator that completion of this project is a priority.

PROGRAM PERFORMANCE IN THE PERIOD

DARLINGTON REFURBISHMENT PROGRAM PERFORMANCE DASHBOARD							
Safety		**Status**	**Trend**	**Schedule Performance Index (SPI)**		**Status**	**Trend**
All Injury Rate (#/200k hrs worked)	0.50		-	Current	0.97		-
# Level 1 Work Protection Events	2			Previous Report	0.96		
Quality			–	**Cost Performance Index (CPI)**			
# Event Free Day Resets	1			Current	0.97		
# Regulatory Non-Compliance	0			Previous Report	1.01		

SAFETY

The 2016 year-end combined All Injury Rate for OPG and contractor employees is 0.50. The AIR exceeded our target of 0.24 injuries per 200,000 hours worked; however, there were no lost time injuries. Safety is our number one priority and zero injuries remains our goal. For comparison purposes, DRP safety performance is seven times better than the construction industry in Ontario.

OPG and our vendor partners are actively communicating the importance of safe work practices in the field. Vendor safety performance has shown continuous improvement since November. OPG has developed a "Seven Life-Saving Rules" campaign which communicates industrial safety to all trades noting that adherence to these rules is mandatory with no tolerance for violations.

Since Unit 2 breaker-open, Radiation Safety Performance has been good with no unplanned exposures.

Additional details on conventional and radiological safety performance, including the "Seven Life-Saving Rules" campaign, are provided in Appendices 1 and 2.

QUALITY

One quality event occurred in the period when the adjuster rod SHIM mode operation could not be placed in service due to a set-point error made during design. A corrective action plan was implemented and the modification is now in-service on all 4 units.

Additional details on quality performance are provided in Appendix 3.

SCHEDULE PERFORMANCE

The DRP SPI reflects schedule performance against the aggressive working schedule, and includes execution of the Unit 2 refurbishment as well as the Facility & Infrastructure (F&IP) and Safety Improvement Opportunity (SIO) projects.

Over the period, the overall program SPI has remained relatively stable and is 0.97, indicating that the DRP is slightly behind plan. The performance is largely due to delayed completion of the F&IP and SIO projects, the construction of the Re-tube Waste Processing Building (RWPB), and execution of some of the non-critical path activities within Unit 2. Details on the delays, including the impact and mitigation activities, are discussed in the following sections of this memo.

UNIT 2 REFURBISHMENT

Defueling was completed on January 11th, 26 days ahead of the working schedule and a full 39 days ahead of the high confidence schedule. As a result, 13 days of risk based schedule contingency valued at [redacted] has been returned to the Program General Reserve.

Since that date, through the vault preparation and bulkhead installation work, the schedule gains achieved during Defueling have been consumed. Key contributors to the delays are unanticipated work (10 days), Vendor Performance (6 days), and vendor and OPG integration (3 days). Vault preparation activities are being managed in an integrated fashion between the Refurbishment project, SNC/Aecon and Darlington station to protect the overall progress on critical path.

Based on current performance and continued challenges with equipment and integration, it is anticipated that additional delays to critical path will occur while executing vault preparations with a forecast completion of the Containment Pressure Test, and Segment 1 of the refurbishment, on March 30th. This is in alignment with the working schedule commitment, and would result in 17 days of high confidence schedule contingency, allocated to the Vault Preparation phase, being unused and returned to the Program General Reserve.

Some near-critical path work, such as the pre-requisite projects, is progressing behind plan; however, OPG, together with the vendors, is actively managing near-critical path activities to recover schedule and avoid any impacts to critical path. The Schedule Performance for the month of January was good with 99% of the 88,500 hours planned for the period being earned. This is a significant improvement over December. In order to reduce the backlog, the program needs to earn more hours than planned, and have a period SPI greater than 1.00. Significant progress was made in the month of January within the Balance of Plant projects. ES Fox schedule performance was greatly improved, including recovery of the Vault Vapour Recovery System (VVRS), Conventional Dry Air, and Breathing Air system projects. This, however, was off-set by delays within the Re-tube Waste Processing Building.

In summary, on March 30th, at the completion of Segment 1, Unit 2 is forecasting to be on plan against the working schedule, and a full 30 days ahead of the high confidence schedule.

Additional details on Unit 2 critical path, including Segment 2, are included in Appendix 4 with further details provided in the monthly Unit 2 Execution Status Report.

COST PERFORMANCE

Since the November report to the DRC, the overall program CPI has declined from 1.01 to 0.97 which indicates that work is being performed for slightly more than budgeted. The decline in the period is largely due to higher costs to complete the remaining F&IP and SIO projects. Additional details on the estimate to complete for these projects, as well as the commercial performance, are included in the following sections of this memo.

FINANCIAL SUMMARY - TOTAL PROGRAM COST

Life-to-Date Cost (M$)			At Completion of Program (M$)				
Actual	Plan	Variance	Forecast	Plan	Variance	◯	↓
3,206	**3,284**	**(79)**	**12,800**	**12,800**	**0**		

Total Program Contingency (M$)					
	Budgeted		Allocated	Unallocated	
2,007	100%	[redacted]			◯ –

The life-to-date cost for the program is $3,206 Million, $79 Million below plan. Primary contributors to the under spend are lower than planned OPG resources, delays in executing some non-critical path Unit 2 work, and timing variance for Unit 3 planning and material procurement. These under spends are off-set by $11 Million of over spend within the F&IP and SIO projects. The forecast to complete the program remains within the approved budget of $12.8 Billion.

In last quarterly report to the DRC, program contingency was reported against the $2,006 Million Release Quality Estimate approved in November 2015. Since then, the program contingency has been reconciled to the Unit 2 Execution Estimate approved in August 2016, which excludes [redacted] of previously drawn contingency that was transferred to the projects prior to approval of the Unit 2 Execution Estimate. The total program contingency that has been allocated since August 2016 is [redacted]. This reflects forecast contingency draws for the F&IP and SIO projects, off-set by returns to contingency as a result of retired risks and interest re-calculations.

FACILITIES & INFRASTRUCTURE AND SAFETY IMPROVEMENT PROJECTS

In the period, work on the remaining F&IP and SIO projects has progressed, and the in-service of both the 3rd EPG and CFVS projects is forecast as mid-March. The cost estimates to complete the work exceed the established budgets, including contingency. [redacted] OPG continues to work through the contract management processes to resolve these issues, and mitigate further impact to the program cost.

Containment Filter Venting System – The equipment was successfully commissioned at the end of January; however, there were some components that were damaged during installation and required replacement prior to final acceptance by OPG. The vendor is currently replacing the deficient components, which has delayed the final in-service date until mid-March. OPG met with the CNSC prior to the end of December to seek an extension to the regulatory obligation and continues to demonstrate to the regulator that completion of this project is a priority. The IIP change control process was initiated, and a revised completion commitment for placing the system fully into service by April 28th, 2017 has been accepted by the CNSC. The target date to have the deficiencies corrected and the system fully in service is mid March, in advance of the CNSC commitment.

The forecast cost to complete the project is $101 Million, an increase of $7 Million since the last report.

3rd Emergency Power Generator – Commissioning of the 3rd EPG continues, and the forecast in-service date is mid March, in advance of the revised IIP commitment of March 31st. The generator is connected to station systems to support completion of the site acceptance testing, and has been started and synchronized. The final connection of the unit to the emergency power bus is planned for the first week of March. The building is completed structurally and final application of exterior cladding and interior painting remain.

The forecast cost to complete the project is $140 Million, an increase of $7.1 Million since the last report.

Heavy Water Storage Facility – Civil construction progressed in the period with the completion of the steel structure, second floor slab and installation of the external building precast panels. The schedule and cost estimate to complete the project is undergoing review with the vendor and OPG, and the final cost to complete the facility will exceed the current budget. Additional details, including mitigation strategies, are discussed in the Commercial and Contractor Performance section of this memo.

The SPI for the F&IP and SIO projects has increased from 0.89 to 0.91 in the period, and will continue to approach 1.00 as the projects are completed. The CPI has declined over the period, and is 0.83. The CPI will continue to decline as potential cost increases are realised.

Based on the current forecasts to complete the F&IP and SIO projects, [redacted] of contingency is required above the $17.9 Million of contingency allocated during Unit 2 Execution Estimate. This will be funded from returns to General Program Reserve.

Additional details on the remaining F&IP and SIO projects are provided in Appendix 6, and Appendix 11 provides photographs of construction activities underway.

RISK, OVERSIGHT AND ASSURANCE

RISKS

During the Defueling and early part of the vault preparation phase, active risk management has been an area of focus. Deployable risk mitigation strategies contributed to the success of Defueling; when risks occurred, plans were well established to mitigate and minimize the impact. Further, risks related to Primary Heat Transport motor failure did not occur resulting in a return of 13 days, and the associated [redacted] in contingency, back to the Program General Reserve.

As expected, while some risks have been retired without events, other events have occurred where risks and appropriate mitigation strategies were not in place. The leadership team has recognized this and has implemented a weekly risk look-ahead process to improve the identification and resolution of any risks, to the extent possible.

The Project Controls team is currently developing a risk tracking report that will show the status of all risks, including those that triggered and their impact, any new risks, and retired risks. This will be integrated with the forecasting process, and will be in place prior to the next quarterly DRC report.

Notwithstanding the fact that there have been a number of minor risk events in the period, there have been no changes to the key program risks since the last report, however, vendor performance risk is a focus area as discussed throughout this report. Details on the program risks, including the mitigation status are provided in Appendix 7.

PROJECT OVERSIGHT AND ASSURANCE

OVERSIGHT FINDINGS

There have been no significant emerging oversight findings identified by the Project and Program Oversight groups in the period. Details regarding current low level and past findings reported to the DRC are documented within the quarterly DRP Assurance Report.

AUDIT AND EXTERNAL OVERSIGHT

In the fourth quarter, there were 10 Internal and Nuclear Oversight audits conducted related to the DRP. Findings were identified in three areas relating to the implementation of Project Manager training, [redacted]'s procurement surveillance tracking, and the monitoring and recovering of costs associated with defective work. Corrective action plans are in place to address the findings and are on-track.

There were two CNSC Type II inspections conducted in the quarter in the areas of On-boarding and Oversight Training Requirements, and Quality Management and Oversight of Project Execution. These inspections noted a number of strengths, and there were no directives issued.

REFURBISHMENT CONSTRUCTION REVIEW BOARD (RCRB)

The Refurbishment Construction Review Board (RCRB) concluded its third visit on December 2nd, and provided three critical areas of focus for the Refurbishment team to improve project performance:

- Work execution needs to improve to prevent future impacts to schedule.
- Schedule stability needs to improve to facilitate schedule execution.

- Tailored Project Reporting which aligns high level program metrics with lower level project and departmental metrics is needed to drive accountability and behaviour.

A number of initiatives were completed to correct the underlying contributors to these observations. They include streamlining the existing project meeting calendar to focus on work readiness and schedule compliance; re-enforcing Project Manager accountability; supplementing both the OPG and vendor organizations with resources to drive work performance and address the backlog of work; and increasing work readiness and ownership of the plan by trades supervision.

A brief follow-up assessment was conducted in early February to status the implementation of the previous reports recommendations. The RCRB noted improvement in the refocus and accountabilities of the Project Manager, an improved scope stability, and an improved schedule performance and SPI with the exception of the RWPB project.

The following positive observations were also noted:

- Critical path performance on defueling has progressed very well, reflecting good team work.
- Good progress has been made with recruitment and on-boarding of staff.
- Steps taken for islanding of Unit 2 are very effective.
- Engineering field change process is working well with efficient issue resolution.
- There is good evidence of the shift to execution; however, continued effort is needed to further simplify processes to support schedule stability.

The RCRB reiterated that the project's most important focus area remains on improving schedule compliance which includes completing the required work that supports the project schedule. They offered a number of additional insights and suggestions to further improve work execution and schedule stability. These suggestions are currently being implemented in Refurbishment.

COMMERCIAL AND CONTRACTOR PERFORMANCE

SNC/AECON COMMERCIAL ISSUES

[redacted] OPG has initiated the following activities to mitigate the potential impact:

1. OPG is performing an independent assessment of the current project status and cost to complete to facility.
2. OPG is working with SNC/Aecon to understand their schedule basis, the reasons for the delays, and the basis for their estimate to complete the facility.

[redacted]

OPG continues to work through the contract management processes to resolve these issues.

ES FOX – PERFORMANCE IMPROVEMENT

[redacted] both OPG and the vendor have prepared plans for improved performance and fieldwork execution. OPG staff has been seconded to ES Fox to help drive the needed improvements. The plan developed by ES Fox focuses on five key areas: leadership and engagement, safety, quality of work, schedule completion, and accountability. Implementation of the improvement activities continues, and initial results with Unit 2 refurbishment projects are positive. Quantified improvement has been observed in the following areas:

- Project Management – Paired OPG and ES Fox Project Managers are fully engaged in driving work readiness and completion, and have produced notable improvement in safety performance.

- Near critical path projects – Completion has improved on near-critical path projects as reflected in the performance of the Breathing Air and Vault Vapour Recovery modifications.
- Backlog Reduction – Field performance has resulted in a significant reduction in the number of labour hours behind plan.

[redacted]

Additional details on vendor performance are provided in Appendix 8.

COMMUNICATION ACTIVITIES

TACTICAL COMMUNICATIONS FOR THE REFURBISHMENT TEAM

As previously reported, Corporate Relations & Communications (CRC) continues to undertake a number of initiatives to expand communication channels, build greater understanding of the project, and re-enforce behaviours expected of employees and trades. The messaging shifted in the fourth quarter of 2016 to the project pillars for execution success; turning on the 'construction switch'; as well as a strong emphasis on meeting our execution schedule commitments.

A number of programs are in place to ensure employees and contractors are aligned and informed. These include:

- An internal employee refurbishment website with weekly stories, daily communications, and access to critical production reports is in place and actively updated with over 70,000 visits per month.
- Monthly leadership messages are now sent from the SVP and senior leaders, supported with a video message. The weekly "Minute with Mike" videos continue to be produced and are receiving positive reviews.
- A metric dashboard was developed and is issued monthly to educate staff on current Key Performance indicators.
- Monthly leadership cornerstone meetings are held with the management team to align the organization around near-term objectives and recognize successes.
- Bi-monthly Standups! (face-to-face sessions) are also held with staff in multiple locations to recognize success and focus employee's attention on the key near-term outcomes.
- A successful employee and vendor event was held in January to acknowledge the successful completion of the defueling campaign.

COMMUNICATIONS TO THE PUBLIC AND STAKEHOLDERS

In the last quarter of 2016, the communications messaging shifted from planning to an execution posture. The external narrative focused on meeting our commitments by providing assurances of how the detailed planning and preparation safely got the project to the starting gate for breaker open on time and on budget.

A concerted external communications push was initiated to coincide with the start of the project on October 14th to leverage a number of highly visible events. A social media campaign supported by a print campaign in newspapers and a series of media releases was launched on November 1st; this resulted in positive media coverage across the province and increased the visits to the OPG Refurbishment website from an average of 19,000 visits to 155,000 in November. A successful public open house with 1800 visitors was held the same weekend.

To further engage the public and key stakeholders, the refurbishment website underwent a refurbishment of its own. The site is now maintained with new content including monthly performance updates as well as staff and vendor feature articles.

On the key stakeholder front, OPG communicated extensively with politicians at all levels of government and across party lines in the period and reached out to 20 different mayors across Ontario. It met with 22 members of Provincial Parliament, including the Conservative Energy critic, the PC caucus, and the NDP energy critic. Refurbishment was also discussed with 10 members of Parliament in Ottawa, including two Cabinet Ministers. This was tied to the province's consultation for their Long Term Energy Plan and resulted in strong endorsement from such groups as the Nuclear Mayor's Technology Caucus, Ontario Chamber of Commerce and Toronto Board of Trade.

In the first quarter of 2017, the social media campaign continued with a high presence on LinkedIn, Twitter and Instagram. A new Darlington TV commercial was shot in February and will be aired in April.

Additional details on internal and external communications are provided in the dashboard Appendix 9.

KEY DELIVERABLES FOR THE NEXT PERIOD

Focus has shifted to the following deliverables in the first quarter of 2017:

- Unit 2 critical path will continue through the Vault Preparations including completion of the reactor bulkhead installation.
- The Unit 2 Primary Heat Transport System vacuum dry will commence.
- External cladding will be installed on the RWPB.
- The Unit 2 Breathing Air enhancement system will be completed and placed-in-service.
- The CFVS and 3rd EPG projects will be placed in-service.
- Unit 2 Segment 1 work will end with the containment pressure test, which is planned for completion March 30th.

Following completion of Segment 1, the Removal Phase, or Segment 2a, will commence. Appendix 4 provides further details on planned activities remaining in Segment 1, and planned activities included in Segment 2a.

Submitted by:

Dietmar Reiner
SVP, Nuclear Projects

APPENDICES

1. Conventional Safety Performance
    a. Conventional Safety Performance
    b. Seven Life-Saving Rules Campaign
2. Radiological Safety Performance
3. Quality Performance
4. Schedule Performance
    a. Unit 2 Critical Path Schedule – Segment 1
    b. Unit 2 Critical Path Schedule – Segment 2
5. Cost Performance
    a. Program Financial Performance
    b. Program Contingency Management
6. Facilities and Infrastructure and Safety Improvement Projects
7. Key Program Risks
8. Vendor Performance Summary
9. Communications
10. Metrics Legend
11. Photo Catalogue

Darlington Nuclear Refurbishment Program

APPENDIX 1A: CONVENTIONAL SAFETY PERFORMANCE

Bundle and Vendor Performance Year-To-Date

Period Ending: 31-Dec-16

SAFETY PERFORMANCE - YEAR TO DATE (YTD)

OPG and Vendor Refurbishment Staff	Actual		Target	Status	Trend
	Previous	Current			
Combined All Injury Rate (AIR)	0.42 [1]	0.50	0.24		-
OPG ONLY All Injury Rate (AIR)	0.00	0.00	0.24		-
# of Days Since a Lost Time Injury		2,556		Since Jan. 1, 2010	

ALL INJURY RATE - 6 MONTH TREND

ote: AIR is reset at Year-End.

BUNDLE SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Line	Project Bundles (Additional Project Bundles will be added as they commence work on site.)	AIR	ASR	Safety Injuries		Safety Incidents		Hours Worked (Thousand)
		All Injury Rate	Accident Severity Rate	# Lost Time Injury	# Medical Injuries	# High MRPH	# Lvl 1 Work Protection Events	
1	Re-tube & Feeder Replacement							
2	Turbine Generator							
3	Fuel Handling & Defueling							
4	Shutdown Lay-up							
6	Steam Generators							
7	Islanding							
8	Balance of Plant							
9	Facilities & Infrastructure and Safety Improvement Opportunity Projects							
10	OPG Refurbishment Staff	-	-	-	-	-	-	1,369.2
9	**Nuclear Refurbishment Performance**	**0.50**	**-**	**-**	**9** [2]	**6** [3]	**2** [4]	**3,612.1**

VENDOR SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Excluding Owner-Only Metrics

Line	Vendors (Additional Vendors will be added as they commence work on site.)	AIR	ASR	Safety Injuries				Hours Worked (Thousand)
		All Injury Rate	Accident Severity Rate	# Lost Time Injury	# Medical Injuries	# High MRPH	# Lvl 1 Work Protection Events	
1								
2								
3								
4								
5								
6								
7	OPG	-	-	-	-	-		1,369.2
8	**Nuclear Refurbishment Performance**	**0.50**	**-**	**-**	**9**	**6**	**2**	**3,612.1**

OWNER-ONLY SAFETY PERFORMANCE - YEAR TO DATE (YTD)

1	Refurbishment Project Office	-	-	-	-	-	-	14.1
2	Re-tube Waste Processing Building	3.42	-	-	4	-	-	234.1

EXPLANATORY NOTES

[1] The 2016 Year-end AIR is 0.50 as a result of 9 medically treated injuries within 2016. There were no Lost Time Accidents. The OPG only AIR is 0.00 as a result of zero medically treated injuries involving an OPG employee. The previous period AIR, September 30th 2016, has been corrected from 0.64 to 0.42 due to understated OPG hours worked. As a result the AIR has declined over the period from 0.42 to 0.50.

[2] Four medically treated injuries occurred in the quarter, including one critical injury. An [redacted] worker on a [redacted] suffered a broken leg when he was struck by an Elevated Work Platform that he was spotting. The injured worker returned to work his next scheduled shift with modified duties. The Ministry of Labour was notified.

[3] Two High Maximum Reasonable Potential for Harm incidents occurred in the quarter. 1) The first incident is related to the previously identified medically-treated injury on the [redacted]. Work was stopped, the crew was stood down and [redacted] implemented a comprehensive improvement plan that included safety. 2) The second incident occurred on the [redacted] when an unqualified [redacted] worker modified a section of handrail while not correctly tied-off, exposing the worker to a falling risk. An inspection of all hand rail and scaffold within the mock-up was conducted to ensure a safe state and communications were rolled out to staff on potential hazards and safety expectations. Performance management of the individuals was conducted.

[4] Two Level 1 Work Protection Events occurred in the period. 1) An [redacted] worker on a [redacted] started to work on, and subsequently operated a valve without authorization. Performance management was conducted. 2) [redacted] workers removed a panel from a transformer cubicle on the [redacted] without having proper work protection in place. Workers were instructed to back out of the work area, and all [redacted] workers were stood down.

Filed: 2017-03-17
EB-2016-0152
J2.10 Attachment 1, Page 9 of 25
Period Ending: 31-Dec-2016

APPENDIX 1B: SEVEN LIFE-SAVING RULES CAMPAIGN

Refurbishment trades safety messaging

SEVEN **LIFE-SAVING RULES** WE MUST ALL ABIDE BY

Following these rules and procedures saves lives. Adherence to these rules is mandatory. **No tolerance for violations.** Breaking the rules may result in discipline up to and including termination.

Care enough to act. Have the courage to intervene if you see an unsafe act or condition or see someone who is unfit for work.

Verify isolation before work begins and use the required protective equipment

Ensure use of fall-arrest or restraint and always maintain 100% tie off

Obtain authorization prior to entry into confined spaces

Operate vehicles safely and stay clear of moving or hoisting equipment

Do not damage or disable safety devices or equipment

Respect work protection. Don't touch guaranteed or tagged equipment

No alcohol, drugs or behaviour that impairs your fitness for duty

Darlington Nuclear Refurbishment Program

APPENDIX 2: RADIOLOGICAL SAFETY PERFORMANCE

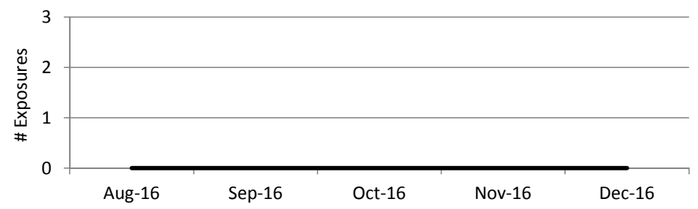
Bundle and Vendor Performance Year-To-Date

Period Ending: 31-Dec-2016

RADIATION PROTECTION PERFORMANCE - YEAR TO DATE (YTD)

OPG and Vendor Refurbishment Staff	Actual	Target	Status	Trend
Unplanned Exposures (>35µCi/l or > 100mrem)	0	0	◯	-

UNPLANNED EXPOSURES - 6 MONTH TREND



↓ is GOOD performance

Unplanned Exposures in Month

Cumulative # Unplanned Exposures - YTD

Note: Cumulative # Unplanned Exposures is reset at Year-End.

BUNDLE SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Line	Project Bundles *Additional Projects will be added as they commence work on site.*	Actual	Target	# Unplanned Exposures	# Precursor EPD Whole Body Dose Alarms	# Unantici-pated EPD Dose Rate Alarms	Precursor Tritium Exposures (>10 µCi/l)	# RP License Violations (Non-PROL)	# Unposted Hazards	# RP Reg Doc. 3-1.1 Violations
		Collective Radiation Exposure (person-rem)								
1	Re-tube & Feeder Replacement									
2	Turbine Generator									
3	Fuel Handling & Defueling									
4	Shutdown Lay-up									
5	Islanding									
6	Balance of Plant									
7	Facilities & Infrastructure and Safety Improvement Projects									
8	OPG Refurbishment Staff	4.4		-	-	1	-	-	-	-
9	Collective Internal Radiation Exposure [All Bundles]	3.7		-	-	-	-	-	-	-
10	**Nuclear Refurbishment Performance**	(1) **16.6**	**18.8**	**-**	**-**	(2) **1**	**-**	**-**	**-**	**-**

VENDOR SAFETY PERFORMANCE - YEAR TO DATE (YTD)

Excluding Owner-Only Metrics

Line	Vendors Additional Vendors will be added as they commence work on site.	***Collective Radiation Exposure (person-rem)***	# Unplanned Exposures	# Precursor EPD Whole Body Dose Alarms	# Unantici-pated EPD Dose Rate Alarms	Precursor Tritium Exposures (>µCi/l)	# RP License Violations (Non-PROL)	# Unposted Hazards	# RP Reg Doc. 3-1.1 Violations
1									
2									
3									
4									
5	OPG Staff	11.5	-	-	1	-	-	-	-
6	**Nuclear Refurbishment Performance**	**16.6**	**-**	**-**	**1**	**-**	**-**	**-**	**-**

EXPLANATORY NOTES

(1) The overall Collective Radiation Exposure (CRE) is below target

(2) There has been one unanticipated Electronic Personal Dosimetry (EPD) dose rate alarm in the quarter. An OPG workers EPD alarmed while they were performing a final vault walk down of all elevations prior to the start of the defueling campaign. An immediate safe back-out from the vault was performed.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 3: QUALITY PERFORMANCE

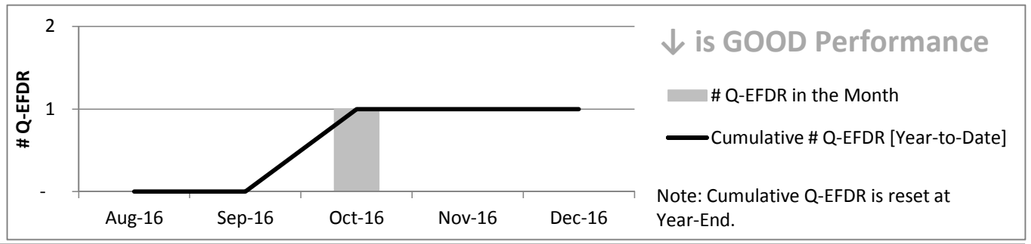
Bundle and Vendor Performance Year-To-Date

Period Ending: 31-Dec-2017

QUALITY PERFORMANCE - YEAR TO DATE (YTD)

	Status		Trend	Days Since Last Q-EFDR
	Previous	Current		
Overall Quality Performance	○	●	—	88 [1]

QUALITY EVENT FREE DAY RESET - 6 MONTH TREND



Note: Cumulative Q-EFDR is reset at Year-End.

BUNDLE QUALITY PERFORMANCE - YTD

Line	Bundles	*Quality Event Free Day Resets (Q-EFDR)*	*Regulatory Non-Compliance Events*	*NCARs*	*OPG SCRs with Major Impact*	*Rework (Execution)*	*Average # of Revisions per Closed-out ECs*
1	Re-tube & Feeder Replacement	[redacted]					
2	Turbine Generator						
3	Fuel Handling & Defueling						
4	Steam Generator						
5	Balance of Plant & Refurbishment Support Facilities						
6	Shutdown, Layup and Services						
7	Unit Islanding						
8	Campus Plan - F&IP and SIO Projects						
9	Refurbishment Operations & Maintenance						
10	NR - Other						
11	**Nuclear Refurbishment Performance**	**[1] 1**	**[2] -**	**3**	**-**	**-**	**2.1**

VENDOR QUALITY PERFORMANCE - YTD

Line	Vendors	*Quality Event Free Day Resets (Q-EFDR)*	*Regulatory Non-Compliance Events*	*NCARs*	*Vendor CARs*	*Rework (Execution)*	*Average # of Revisions per Closed-out ECs*
1	[redacted]						
2							
3							
4							
5							
6	OPG	1	-	-	-	-	-
7	**Nuclear Refurbishment Performance**	**1**	**0**	**3**	**-**	**-**	**2.1**

EXPLANATORY NOTES

1. One Q-EFDR occurred in October on a Balance of Plant project when the adjuster rod SHIM mode operation could not be placed in service due to a set-point error made during the design analysis. A corrective action plan was initiated and the modification is now in-service on all 4 units.
2. A regulatory non-compliance event previously reported to the DRC in November was related to [redacted], a non-refurbishment project. As such, the event is not included in this report; however, interim actions have been taken to prevent reoccurrence.
3. Two NCAR have been issued to the [redacted] in the quarter regarding the [redacted]. The findings involved repeat quality records issues and an observed trend of not meeting requirements of the OPG's Approved Supplier Listing. Corrective actions are in place. The NCAR related to [redacted], identified in the previous report to the board, has been removed since it occurred on the [redacted] which is not a refurbishment project. The remaining [redacted] NCAR refers to the previously identified issue related to a less than acceptable safety focus.

**NCAR = Non-conformance and Corrective Action Request; SCR = Station Condition Record; CAR = Corrective Action Request; EC = Engineering Change;*

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 4A: UNIT 2 CRITICAL PATH SCHEDULE - SEGMENT 1

Performance of Critical Path against Working Schedule

Period Ending: 14-Feb-17

DARLINGTON REFURBISHMENT Repowering Ontario

S1

Unit 2 Refurbishment: SEGMENT 1 Defuel + Containment Isolation

CURRENT: 161 days: October 15, 2016 – March 25, 2017

Critical Path Windows; Electrical Windows; Conventional Layup; Heat Transport Vacuum Dry; Other required S1 work

Unit 2 Segment 1 Status Update: February 14, 2017 @ 17:00

October 2016 | November 2016 | December 2016 | January 2017 | February 2017 | March 2017 | April 2017

2 Conventional Side LAY-UP

Drain & Protect (Lay-up) Conventional Systems from Corrosion

21-Oct-16 OPS Apply Drain OTO's & [illegible] COMPLETE — 01-Nov-16 Install Dehumidifiers & Establish Airflow Path COMPLETE — 10-Jan-17 ~~28-Dec-16~~ — Commission and Dry Conventional System COMPLETE — 10-Feb-17 ~~09-Jan-17~~ Systems Declared in Lay-up — 22-Feb-17 OTO Permit Application

Deadlegs Drained — 20-Feb-17

To inhibit corrosion damage to secondary side steel piping systems caused by moisture, temporary dehumidified air is provided. (11) Dry Air skids will be installed at various points to force warm air through the pipework in order to achieve acceptable dryness.

Layup Completion for the following systems:

DHA1:	Main Condenser
DHA2:	Boiler Feedwater
DHA3-4:	Main Condensate
DHA5:	Main Steam
DHA6-7:	Extraction Steam
DHA8-9:	Main Steam Reheat
DHA10:	D/A, Condensate Make Up & Storage Tanks
HP1:	FW Pumps (Main & Aux)

4 PRIMARY HEAT TRANSPORT SYSTEM VACUUM DRY

The entire HT system must be drained & dried before the retube of the reactor can begin. Once Operators have drained it through normal pipework, the Heat Transport system will be put under vacuum in order to 'boil off' the rest of the water. A Vacuum Drying Skid will be attached to the HT system to perform this. The water vapor will be condensed in receivers and sent through piping to the storage tanks outside of Unit 2. It is expected to take 40 days to completely drain & dry the HT system

Heat Transport Motors Disconnect and Uncouple 33120-PM1, PM2, PM3, PM4 — Remove Heat Transport Motors

Vault Access Coordination for HT Motors due to Vault Access restrictions during Critical Lifts

Defuel Complete 11-Jan-17 @19:49 ~~06-Feb-17~~ — Declaration that Reactor Core is Defueled Before Entering State 3a

16-Jan-17 ~~11-Feb-17~~ — Vac Dry Prereqs — 25-Feb-17 ~~04-Mar-17~~ — Heat Transport Vacuum Dry — 19-Mar-17 ~~22-Mar-17~~

HTS Bulk Drain

30-Mar-17

Unit 2 Shut Do[illegible]-16 — West RAB Brake Repair

Shutdown Unit 2 — First things first...

Unit 2 will start reducing power at 22:00 hrs on Friday Oct 14. At midnight (Oct 15th at 00:00 hrs) Operators will fire Shutdown System #2 to take the Unit deeply sub-critical. The Heat Transport System will be cooled down to 80 C to allow defueling of the reactor to take place. Years of planning has led us to this milestone to open the breaker on the first Darlington Refurbishment Unit!

1 — 308 Channels: Single Flow Defuel — 29-Nov-16 @11:00 ~~06-Dec-16~~ — 36 Channels: Single End Flow Defuel — 08-Dec-16 @08:00 ~~02-Jan-17~~

1 DEFUEL

The reactor will be entirely defueled prior to turnover to the Joint Venture who are going to be performing the Retube of the Unit 2 reactor and replacing feeders. The majority of the defuel campaign will be accomplished via flow defueling using the Heat Transport pumps however it is estimated that 124 dummy fuel bundles (11 per channel) will need to be installed in the low flow channels allow push defueling to empty the channel.

480 Channels Defueled!

Window D17 Install APT, End Fitting Caps & Radiation Shielding — 15-Jan-17 ~~8-Feb-17~~ Window D15 Vault Crane Maintenance Complete — 15-Jan-17 Window 200 Shield plug swap

EAW Carriage Removal Complete 4-Feb-17 ~~17-Feb~~

Window 23 Bulkhead Installation — Bulkhead Installation Complete — STOP — Containment Pressure Test Declared Complete — 24-Mar-17

Window 24 Containment Pressure Test

To the start of Segment 2 Window 137

3 'ISLAND' Unit 2 from the DNGS Operating Units

A large steel bulkhead to bridge the gap where the fueling machines access the U2 reactor will be installed during this window. This bulkhead will form part of the temporary containment boundary which will physically separate Unit 2's containment from the operting units!.

5 VERIFY UNIT 2 is isolated from containment

The containment test is conducted to verify the integrity of the new containment boundary.

New Breathing Air System Installation

Install Mechnical Portion of Breathing Air — 30-Jan-17 — COMPLETE

Install Electrical Portion of Breathing Air — 13-Feb-17 OCD — COMPLETE — 16-Feb-17 — Commission Breathing Air Outside Vault — OCD 15-Mar-17 — Breathing Air Final Tie-in and AFS 28-Mar-17

New Breathing Air Tie-in for Refurbishment use in Unit 2 will be performed at the start of Segment 2

Segment 1 Major Electrical Scope

21-Oct-16 — W126: T9/T1[illegible] Maintenance COMPLETE — 11-Nov-16 — To Odd Electrical Outage (Segment 2)

15-Nov-16 — W127: T10/T12 COMPLETE — 03-Jan-17 — To TPDS and Odd Electrical Outage in S2

VVRS 3-Way Valve Replacements — COMPLETE — 30-Dec-17

VVRS ByPass Fan Installation — COMPLETE — 8-Feb-17 OCD — 15-Feb-17

Window 009: VVRS Modifications

W009: VVRS Modifications — COMPLETE — 30-Jan-17 — To Containment Pressure Test

State 1: Reactor Shutdown Evolution | State 2: Guaranteed Shutdown with Irradiated Fuel Core | State 3a: Defueled State | State 3b: Defueled & Isolated from Containment State

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - Unit 2

APPENDIX 4B: UNIT 2 CRITICAL PATH SCHEDULE - SEGMENT 2

Level 1 Critical Path Working Schedule for Segment 2

Period Ending: 14-Feb-17

DARLINGTON REFURBISHMENT Repowering Ontario

S2a

Unit 2 Refurbishment: SEGMENT 2a Removal Phase

213 days: March 30, 2017 – October-29, 2017

Critical Path Windows | Electrical Windows | Moderator Windows | Heat Transport Vacuum Dry | Other required S2 work | Near Critical windows | Water Systems

U2 Schedule S2a
February 28, 2017

March 2017 | April 2017 | May 2017 | June 2017 | July 2017 | August 2017 | September 2017 | October 2017 | November 2017

13-May-17 HTS Aux Vac Dry — Window 035
HTS Auxiliaries - Drain & Purge (Layup) — Window 048
40% fill Achieved
HTS Auxiliaries - Rehab — Window 048

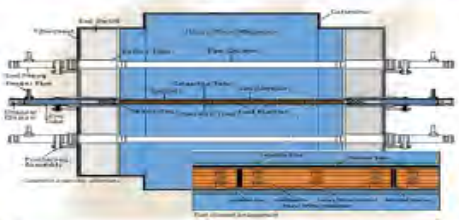
D1711 Outage

Holdout for Boiler Manway Manipulator Arms (Unit 1 Integration Logic)

PHT Vac Dry — Window 029
PHT Vac Dry (Continued) — Window 029
13-May-17 Primary Side SG Layup 17-Jun-17 — Window 034
PHT Vac Dry stops during the Containment Pressure Test

6 Primary Side Steam Generator Layup

Following the vacuum dry of the Primary Heat Transport System which includes the Primary Side of the SG's, the SG Primary Side will be put into a dry air layup state. The purpose of the dry air layup is to minimize degradation of existing system assets during planned maintenance and to reduce the tritium hazard to the extent possible.



4 Vault Projects

Once the Air lock doors are open there are various projects to be executed in coordination with the work on Critical Path. The vault project work consists of Piping installation for the Emergency Heat Sink Lines, Periodic Inspection Programs, valve overhauls and install, igniter cables and Shutdown Cooling cables

Window 104: Vault Projects
Window 105: Vault Projects
Airlock 2 Shielding Curtain Installed for Work in Progress

VERIFY UNIT 2 is isolated from containment 30-Mar-17

Segment 1 — 8d — 7-Apr-17

Window 025: Install Shielding — 19d — 26-Apr-17
Window 027: Bulk Interference Removals — 23d — 19-May-17
Window 101: Remove EM Bridges & Install RTP — 42d — 30-Jun-17
Window 111: Feeder Cabinet Removal — 16d — 16-Jul-17
RFR JV Vault Access Only
Window 042: Feeder Removal — 51d — 5-Sep-17
Window 192: Dummy FB Removal — 9d
Window 112: Pressure Tube Sever — 14d — 28-Sep-17
Window 113: Sever Bellows — 31d — 29-Oct-17
To the Start of Segment 2b Window 114 End Fitting Removal

1 Opening of Airlock Doors

Window 137: Once the Bulkheads are installed and the Pressure test is complete, the Airlocks will be opened to facilitate large numbers of workers in the vault and critical logistics. ViRS System and By-pass fans are commissioned as well as the final Breathing Air tie-in to remove reliance on use of Breathing Air from the Station Breathing Air system.

2 Vault Setup and Feeder Removal Prep

GETTING THE VAULT READY FOR REACTOR DISASSEMBLY

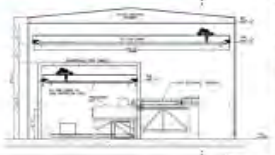
Windows 025, 027, 101, 111

The vault needs to clear of all interferences to make room for tooling and equipment required to disassemble the reactor.

3 Reactor Disassembly

Windows 042, 192, 112, 113

A special platform (Retube Tooling Platform) will be installed to support retube tooling. Feeders will be cut into small, manageable pieces and lowered to the floor where they will be cut up even further for transport to the on-site waste processing building. Once the Feeders are removed. The Pressure tubes will be cut and End Fittings and Bellows will be cut.



14-Sep-17 RWPB Available

The Retube Waste Processing Building (RWPB) is required as part of the RFR project to support the Waste Tooling System (WTS) to optimize Radioactive waste processing and packaging operations.

Retube Waste Processing Building

5 Moderator Drain & Dry

Once the moderator has been drained & flushed, the pipe work can be disconnected to allow vac drying to occur. The calandria is isolated from the lower moderator piping. Calandria Vessel Purge Flow is required to be established for the start of the replacement of the calandria tubes and throughout the calandria tube install series.

Isolate Calandria from Main Pipe work and Hook up Drying Equipment
13-May-17 Moderator Drain & Flush — Window 038
12-Jun-17 — Window 108
10-Jul-17 Establish Upper Calandria Purge Flow and EW Valve maintenance — Window 103
1-Oct-17 — Window 098, CTI Release

Holdout to Align Resources with Horizontal Flux Detector Replacement
Window 028
20-Oct-17 Replace Vertical Flux Detector

From Window 035 HTS Aux Vac Dry
Window 067 — EP Modifications and Run Hose for Vac Dry
Window 121 — Vac Dry Lower Moderator Pipework
3-Sep-17 Moderator Valve Rehab — Window 122
28-Sep-17
Window 123 — Remove Vac Dry Equipment
Window 124 — Purge and 33410 - SDC HX 1 Installation

Holdout for Resources
10-Jul-17 Secondary Side SG Clean & Install Access Ports — Window 037 — 28-Aug-17
BBD Ties to CW AWPP

Segment 2a Major Electrical Scope

Hold out for Temporary Containment Boundary Declared & Temp Vault ACU's installed
16-Apr-17 EPS MCC Rehab — Window 005 — 4-Jun-17
Class 3 Electrical Maintenance — Window 041 — 4-Oct-17
Class 2 Electrical Maintenance — Window 040

Hold out for Warmer Temperatures
3-Apr-17 MOT/UST/IPB/Switchyard Rehab — Window 004 — 15-Sep-17 — To RCHP 5

Segment 2a Water Systems Scope
8-Sep-17 PULSW Outage — Window 056 — Continued in Segment 2b

State 3a: Defueled State
State 5b: Defueled & Isolated from Containment State

ONTARIO POWER GENERATION

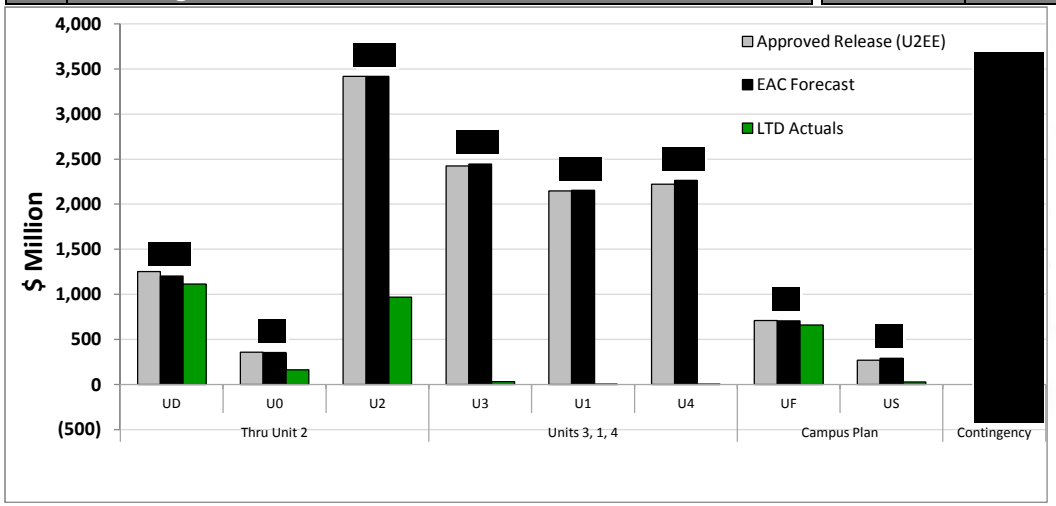
Darlington Nuclear Refurbishment Program

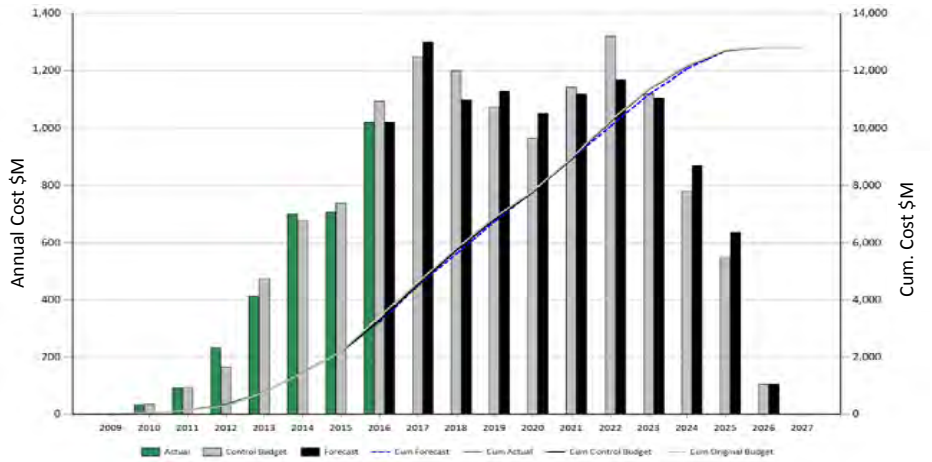
APPENDIX 5A: PROGRAM FINANCIAL PERFORMANCE BY UNIT

Financial status of the Program by Unit

Period Ending: 31-Dec-16

		Cumulative Life to Date			At Completion of Program				
		a	*b*	*c = b - a*	*d*	*e*	*f = d+ e*	*g*	*h*
Line	Description	Plan (PV)	Actual (AC)	Cost Variance From Plan	Approved Plan @ U2EE	Contingency Allocation by Unit	Approved Plan including Contingency	Current Forecast	Approved Funding Release
1	Unit D or Definition Phase	1,105	1,113	**8**	1,251	-	**1,251**	[redacted]	1,251
2	Unit 0 or Unit Common	193	163	**(30)**	359	-	**359**		359
3	Unit 2	1,028	968	**(60)**	2,740	677	**3,417**		3,417
4	**Subtotal Thru Unit 2**	**2,327**	**2,244**	**(83)**	**4,350**	**677**	**5,028**		**5,028**
5	Unit 3	62	31	**(31)**	1,867	557	**2,424**		46
6	Unit 1	9	0	**(9)**	1,739	410	**2,148**		51
7	Unit 4	9	0	**(9)**	1,878	345	**2,223**		5
8	**Subtotal Units 3,1,4**	**81**	**31**	**(50)**	**5,484**	**1,311**	**6,796**		**102**
9	Unit F - Facilities & Infastructure	665	661	**(4)**	690	18	**708**		708
10	Unit S - Safety Improvement Initiatives	254	269	**16**	269	-	**269**		269
11	**Subtotal Campus Plan**	**919**	**930**	**11**	**959**	**18**	**977**		**977**
12	Contingency				2,007	(2,007)	-		*incl. above*
13	**Total Program**	**3,284**	**3,206**	**1 (79)**	**12,800**	**(0)**	**12,800**	**12,800**	**2 6,104**





EXPLANATORY NOTES

1. As of Dec 31, 2016, actual cost to-date was $3.2 Billion, $79 Million under spent: $83 Million through Unit 2 due to lower than planned resources and rescheduling of planned work; and $50 Million for planning and procurement for subsequent units; offset by a $11 Million over spending in Unit F and S Campus Plan projects and [redacted] of contingency allocation (from the Release Quality Estimate).
2. The cost estimate to complete the 4-Unit refurbishment remains within $12.8 Billion.
3. The total forecast for the Facilities & Infrastructure and Safety Improvement projects is [redacted]. This includes the [redacted] required for the key F&IP and SIO projects discussed in Appendix 6, plus [redacted] of minor miscellaneous projects included within the Campus Plan portfolio.
4. The forecast need for additional contingency will be funded from under-spends held in Program General Reserve. Appendix 5B provides details on contingency use and forecast to date.

Darlington Nuclear Refurbishment Program

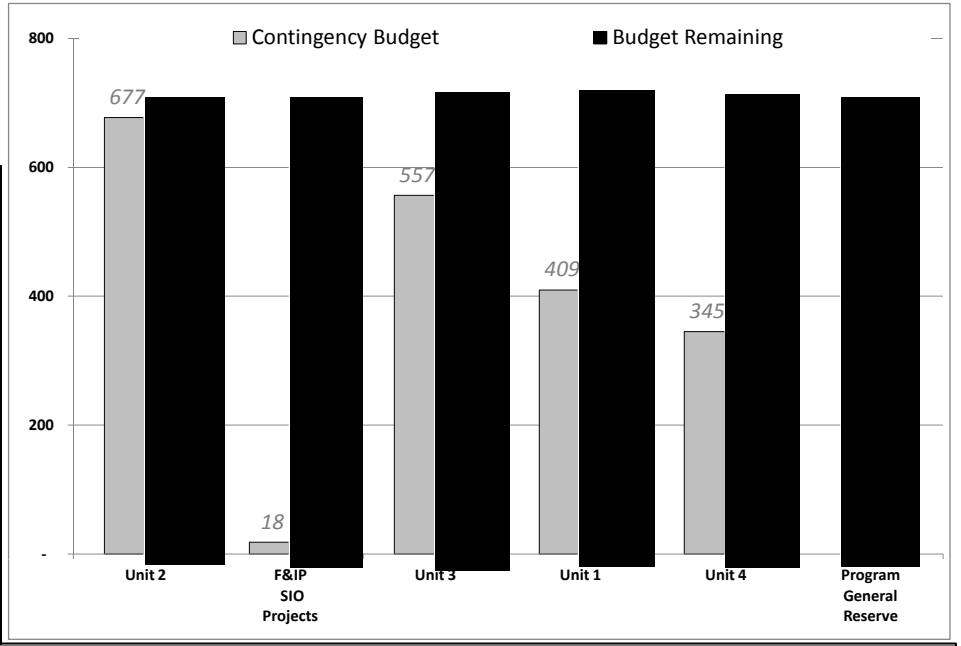
APPENDIX 5B: PROGRAM CONTINGENCY MANAGEMENT

Financial Status of the Program Contingency by Unit

Period Ending: 31-Dec-2016

UNITIZED CONTINGENCY MONITORING AND TRACKING ($ Million)

a	*b*	*d*	*e*	*f*	*g*	*h=d:g*	*i*
Line	Unit	Approved Release @ U2EE (1)	Drawdowns against U2EE	Transfers **to** General Reserve	Transfers **from** General Reserve	**Budget Remaining**	Current Forecasted Need
1	Unit 2	677	[redacted]				
2	F&IP & SIO Projects	18					
3	Unit 3						
4	Unit 1	409					
5	Unit 4						
6	Program General Reserve						
7	**Total Program**	**2,007**					



EXECUTIVE DISCUSSION

1. Contingency in the last Quarterly report was shown against the $2,006 Million original Release Quality Estimate (RQE) budgets. Going forward, contingency will be shown against the $2,007 Million U2EE Board Release approved in August 2016, which excludes [redacted] of contingency drawn and transferred to bundle project base cost as part of U2EE.
2. To-date, there is a net [redacted] contingency draw against U2EE approved budgets:
   - [redacted] drawn was F&IP/SIO projects due to vendor under estimation of costs and quality issues.
   - Within Unit 2, [redacted] of net drawdown is largely a result of [redacted] draw for Balance of Plant projects to address minor scope changes, field execution issues, and revised vendor estimates; [redacted] draw across multiple projects of which [redacted] of due to discrete project risk realization, and [redacted] due to estimating uncertainty; and an off-set of [redacted] of contingency return within the functional projects.
3. A Program General Reserve (PGR) has been established to set aside funding when significant risks are retired. The current [redacted] within the reserve is a result of [redacted] retired high confidence schedule contingency due to the early completion of Defuel, and a [redacted] forecasted interest cost reduction on the nearly complete definition phase. A positive PGR balance represents available contingency funding, whereas a negative balance represents the Program is temporarily consuming more than expected.
4. F&IP and SIO projects are currently forecasting an additional cost over-run of [redacted] which will be funded from surplus held in Program General Reserve.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program - F&IP and SIO

APPENDIX 6: FACILITIES & INFRASTRUCTURE AND SAFETY IMPROVEMENT OPPORTUNITIES PROJECTS

Cost and Schedule Performance

Period Ending: 31-Dec-2016

COST DETAIL ($ MILLION)

		Cumulative (Life-to-Date)					At Completion of Project				In-Service Date			
		a	b	c=b-a	d	e	f	g	h	j	k	m	n	o
Line	Project Title	Plan (PV)	Actual (AC)	Variance	CPI	SPI	U2EE Budget [1]	Estimate at Completion (EAC)	Variance from U2EE	Variance from Last Period	Need Date	Current Forecast	# Months Float	Variance from Last Period
1	Heavy Water Storage & Drum Handling Facility	346.0	340.9	(5.2)	0.86	0.87	381.2	381.1 [2]	(0.0)	0.0	-	Jun 2017	0	1
2	3rd Emergency Power Generator	128.2	135.7	7.5	0.78	0.93	120.4	140.0 [3]	19.6	7.1	Mar 2017 (IIP Commitment)	Mar 2017	0	3
3	Containment Filtered Venting System	84.0	93.9	9.9	0.82	1.02	80.6	101.0 [4]	20.4	7.0	Apr 2017 (IIP Commitment)	Mar 2017	1	4
4	Shield Tank Over Pressure Protection	21.3	20.5	(0.8)	0.78	0.99	24.1	32.7	8.6	0.0	U1-D1711 U2-DNRU2	U1-D1711 U2-DNRU2	0	N/A
5	Balance of Pre-Requisite Projects In-Service	330.8	327.2	(3.6)	*	*	337.7	328.0	(9.8)	(0.2)	IN SERVICE			
6	**Subtotal Campus Plan Before Contingency**	**910.3**	**918.2**	**7.8**	*	*	**943.9**	**982.8**	**38.8**	**13.9**				
7	**Project Contingency (included)**	*	*	*	*		[redacted]							
8	**Program Contingency**	*	*	*	*									
9	**Total Campus Plan including Contingency**	**910.3**	**918.2**	**7.8**	*	*								
Portion of the Re-tube & Feeder Replacement Bundle														
12	Re-tube Waste Processing Building	144.9	119.2	(25.7)	1.05	0.84	180.7	190.2	9.5	(3.2)	Oct 2017	July 2017	2	1

Notes: * Indicates not applicable. The CPI and SPI calculations exclude project management costs and support tasks which are considered level of effort. PHT = Primary Heat Transport

EXECUTIVE DISCUSSION

1. The Budgets have been adjusted to reflect the Unit 2 Execution Estimate budgets, including the contingency.
2. The Heavy Water Storage Facility in-service date and estimate is at risk. The vendor is preparing a cost and schedule estimate to complete the work, and OPG will fully validate this estimate as well as perform an independent review and estimate to complete. Commercial discussions at the CEO level are already occurring, and contingency measures for heavy water storage for Unit 2 are in place.
3. The estimate to complete the 3rd EPG project has increased since the last report as a result of delays in construction, and commissioning complexity; this has resulted in a delay of the in-service date to March 2017. The IIP Change Control Process was initiated and accepted by the CNSC with a revised need date of March 2017.
4. The estimate to complete for the CFVS project has increased since the last report as a result of delays in construction and additional commissioning costs. The in-service date is forecast March 2017. The IIP Change Control Process was initiated and the revised in-service commitment of April 28th has been accepted by the CNSC.
5. A total of [redacted] of additional contingency, above the contingency allocated during the Unit 2 Execution Estimate, is required to complete the projects based on the current estimates. This will be funded from the Program General Reserve. This is an increase of [redacted] in the period.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 7: KEY PROGRAM RISKS

Risks Being Actively Managed by the Program

Period Ending: 31-Dec-2016

KEY PROGRAM RISKS AND MITIGATION STATUS

Line	Status	Risk Description	Mitigation Plan
1	-	**Vendor Performance** Poor vendor performance will negatively impact safety, quality, cost and/or schedule.	Vendor Performance continues to challenge the Refurbishment program and, although there has been some improvements in the quarter, this remains a high risk. OPG continues to actively manage and assist vendors by removing barriers to work and seconding OPG staff to the vendors. Focus areas in the past quarter have been on 1) supervisory training, 2) work readiness, 3) safety awareness and performance improvements, and 4) increasing project manager accountability. Vendor accountability continues to be reinforced through a number of avenues including a weekly performance meeting with focus on safety, quality, schedule and cost performance; vendor ownership levels are continuing to improve. [redacted] ES Fox performance improvement plan in in place which includes secondment of some OPG staff. Quantified improvement has been observed within the refurbishment projects.
2	-	**Availability/Retention of Project Leadership** Key project personnel with the required skill set will not be in place for the full refurbishment program resulting in impacts on performance.	Focus remains on establishing a strategic resourcing framework with the right organizational design, and ensuring the right leadership pipeline is in place for future unit refurbishments (Units 3, 1, 4). Phase 2 of the Nuclear Fleet Bench Strength Improvement Plan is in progress. The Simplified Hiring item on the Nuclear Refurbishment top 10 priority list have been completed, with the central resourcing team currently in place and single point of contacts assigned to support each organization in the expedition of staffing needs. The resource plans have been compared against RQE staffing forecasts to ensure alignment. The Executive Compensation Framework has been finalized.
3	↑	**Availability of Skilled Craft Resources/ Supervision** Key skilled craft resources may not be available when required for the Execution Phase.	Focus continues on the onboarding for trades workers and the New To Nuclear (NTN) program for Unit 2. OPG participates in labour market information studies to gain insights into labour market issues, including the identification of skilled craft resource needs using tactics that include both short and long term approaches. There is no significant risks perceived for Unit 2, however there is a risk to future units with the start of the Bruce Power Major Component Replacement program in 2019. Discussions and collaboration with Bruce Power continue and it is expected this risk will be mitigated. The current plans and tactics are being evaluated to ensure integration with the Nuclear fleet to minimize the risks in all support areas. Provisions in trades union agreements also provide for resourcing flexibility, all major unions signed Nuclear Project Agreement (NPA).
4	↓	**First of A Kind/First in A While Work and Processes** A lack of recognition of FOAK/FIAW work and processes during design and execution planning results in installations that do not meet requirements causing rework/delay or degraded production post Refurbishment.	A thorough and in-depth review was completed with Engineering, project teams and various execution and functional groups in the Nuclear Refurbishment and Projects & Modifications organizations to flag FOAK/FIAW risks. Specific mitigation actions are defined for FOAK/FIAW risks, and In-depth challenge/review of risks impact/events along with robust tracking of the mitigation actions were put in place. Through the defueling phase, active and deployable risk management contributed to a successful campaign, however, weaknesses in proactive risk identification and mitigation have been seen elsewhere, and, as a result, a weekly risk look ahead process has been put in place to reinforce active risk management. A detailed risk tracking module is currently being developed and will be in place by the end of this period (March 30, 2017).

- No change over period
↑ Improvement
↓ Decline

HIGH RISK LOW RISK

Darlington Nuclear Refurbishment Program

APPENDIX 8: VENDOR PERFORMANCE SUMMARY

Core Refurbishment and Facilities & Infrastructure and Safety Improvement Projects

Period Ending: 31-Dec-2016

VENDOR PERFORMANCE INDICATORS

Line	Vendor Name & Key Scope	Safety	Quality	Cost	Schedule	Relationship	Explanatory Notes
1	[redacted]						
2							
3							
4							
5							

Note: The CPI and SPI calculations exclude project management costs and support tasks which are considered level of effort.

ONTARIO POWER GENERATION

Darlington Nuclear Refurbishment Program

APPENDIX 9A: COMMUNICATIONS - EXTERNAL INITIATIVES

Period Ending: 31-Dec-2016

External Initiatives and Outcomes

Narrative Focus: *environmental benefits, jobs and economy; project well planned – started in October as committed*

- Refurbishment website enhancements featuring staff/vendor stories and improvements to navigation
- Public newsletter issued (125K circulation)
- Launched an interactive map listing manufacturers/vendors
- Launched monthly project updates to stakeholders
- Successful public/stakeholder breaker open launch: 1,800 visitors
- Social media campaign launched November 1, supported with a print campaign

Q4 2016 (Oct, Nov, Dec)

SOCIAL MEDIA
TWITTER Q4
37 Number of posts
503 Total interactions

UNIQUE MEDIA STORIES
18 Total
10 Positive
2 Neutral
6 Negative

PRINT ADS PUBLISHED 3

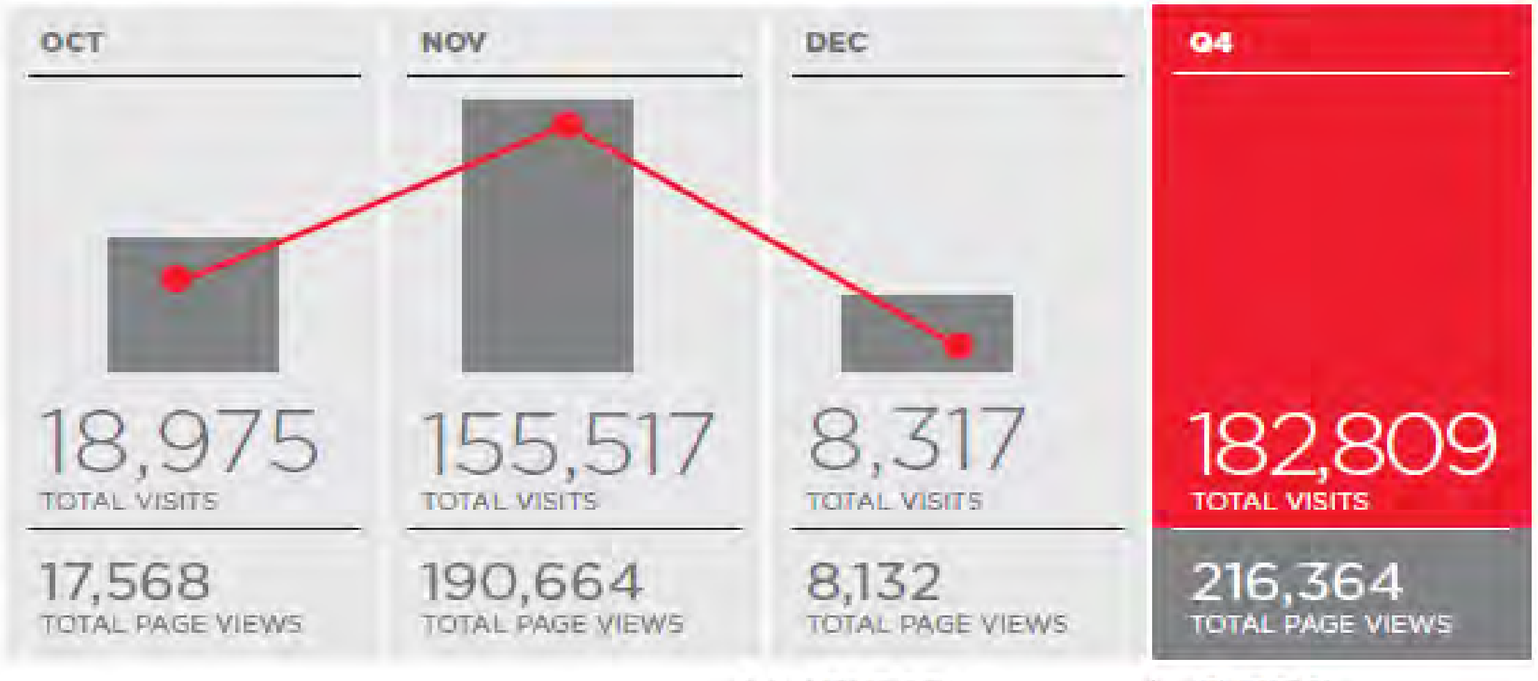
MEDIA RELEASES ISSUES 5

REFURB FALL NEWSLETTER (125K CIRCULATION) 1

MOCK-UP TOURS PRESENTATIONS Q4
Total
18

STAKEHOLDER COMMUNICATIONS AND PROJECT UPDATE REPORTS 7

OPG Refurbishment Website



VENDOR INTERACTIVE MAP | 7,755 TOTAL VISITS

Downloads

Future Objectives

- Development of an interactive online project schedule (what's involved in refurbishment)
- Enhanced frequency of project stakeholder update
- Implement enhanced search engine optimization tactics

ONTARIO POWER GENERATION

APPENDIX 9B: COMMUNICATIONS - INTERNAL INITIATIVES

Period Ending: 31-Dec-2016

DARLINGTON REFURBISHMENT COMMUNICATIONS UPDATE

Q4 2016 (Oct, Nov, Dec)

Internal Initiatives and Outcomes

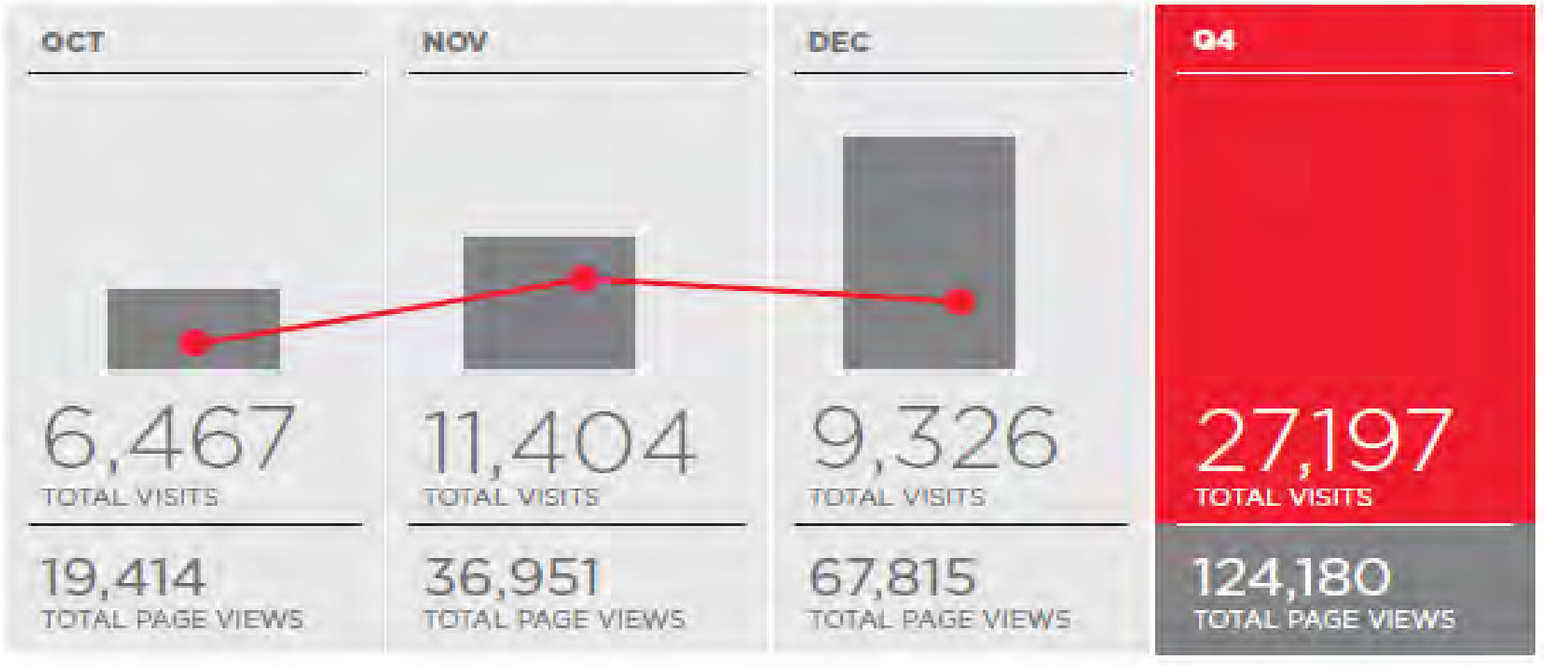
Narrative Focus: *project pillars, turning on the construction switch, OneTeam, shift from planning mindset to execution*

- Re-launched refurbishment website with value-added content and daily updates – paying strong dividends
- Successful employee/vendor breaker-open launch
- Shift to execution posture for communications – numerous daily and weekly updates
- Effective use of weekly video updates to engage staff
- Executed a successful employee/vendor recognition for defuel campaign completion (Q1 2017)

Q4 Combined Results

12 Weekly e-pulse news emails	5 Bi-monthly ***The Pulse*** (newsletter for the trades)	18 Project/leadership videos	
22 Project update stories	37 Refurbishment communications advisories issued	5 Stand-up face-to-face staff alignment meetings	11 Dir of operations/ leadership notes

Refurbishment Employee Website



Future Objectives

- Continue to build traffic to refurb website and enhance user experience and interactions
- Leadership/staff alignment rollout for segment two
- Advancement of communication vehicles targeting trades

ONTARIO POWER GENERATION

APPENDIX 10: METRICS LEGEND

DARLINGTON REFURBISHMENT PROGRAM PERFORMANCE DASHBOARD

METRIC/DESCRIPTION	TARGET	Excellent	Good	Moderate	Poor	↑ – ↓
COST PERFORMANCE INDEX (CPI) Ratio that measures the financial effectiveness. **SCHEDULE PERFORMANCE INDEX (SPI)** Ratio of schedule efficiency to date.	**1.00**	**1.01-1.05**	**1.06-1.09** **0.95-1.00**	**>1.09** **0.91-0.94**	**<0.91**	Managements assessment on the current performance trend. ↑ Performance is IMPROVING – Performance is MAINTAINED ↓ Performance is DECLINING
ALL INJURY RATE (AIR) (# Safety Events/200k hrs worked) Safety events are categorized as the number of fatalities, lost-time injuries, medical treatment injuries and other injuries/illnesses. **The safety statistics include both OPG and contractor performance year-to-date (i.e. reset in January).**	**0.24**	**AIR ≤0.19 AND WP Events = 0** AIR is significantly below target AND zero Work Protection Events in the quarter	**AIR 0.20- 0.37 AND WP Events = 0** AIR is at or below target AND zero Work Protection Events in the quarter	**AIR 0.38-0.41 OR WP Event = 1** AIR is above target within 10% OR 1 Work Protection Event occurred in the quarter	**AIR >0.41 OR WP Event ≥2** AIR is above target > 10% OR ≥2 high Work Protection Event occurred in the quarter	
# LEVEL 1 WORK PROTECTION EVENTS Count of the number of Level 1 Work Protection Events on DRP over the quarter.	**0**					
# EVENT FREE DAY RESETS (EFDR) The number of Darlington Site Event Free Day Resets that occurred within the quarter as a direct result of work being performed within the Darlington Refurbishment Program. The criteria are aligned to the nuclear industry standards and applied consistently across the sites to allow performance comparisons and benchmarking.	**0**	**BOTH at ZERO**	**BOTH at ZERO** Cumulative # of events for the quarter is 0, however previous performance was moderate or poor OR management assessment on low level trending	**EFDR + REG. = 1** Cumulative # of events for the quarter is 1. OR management assessment on low level trending	**EFDR + REG. ≥ 2** Cumulative # of events for the quarter is greater than, or equal to 2 OR management assessment on low level trending	
# REGULATORY NON- COMPLIANCE The number of regulatory non-compliance events related to quality that have occurred within the quarter.	**0**					

FINANCIAL SUMMARY

CURRENT APPROVED RELEASE refers to the total budget of the last release approved by the Board of Directors. The last release was approved by the Board in November 2015, and was to complete the Mobilization Phase.
MOBILIZATION PHASE refers to the work completed Dec 31, 2015 (end of Definition Phase) to October 15, 2016 (Unit 2 Breaker Open).
TOTAL PROGRAM refers to the refurbishment of all 4-units.

METRIC/DESCRIPTION		Excellent	Good	Moderate	Poor	↑ – ↓
LIFE-TO-DATE COST (M$)		Management's assessment based on: Current cost performance; Estimate at Completion; and Contingency allocation.				Managements assessment on the current performance trend. ↑ Performance is IMPROVING – Performance is MAINTAINED ↓ Performance is DECLINING
ACTUAL	Total Program costs incurred to date against the Approved Release.					
PLAN	Planned Program costs to date for the Approved Release.					
VARIANCE	Variance of Actual to Plan. ($) indicates underspend vs. plan.					
AT COMPLETION OF MOBILIZATION PHASE						
FORECAST	Forecast of total Program costs at the end of Mobilization phase.					
PLAN	Planned Program costs at the end of Mobilization phase as per the Approved Release.					
VARIANCE	Variance of Forecast to Plan. ($) indicates underspend vs. plan.					

PROJECT PERFORMANCE INDICATORS AND TRENDS

METRIC/DESCRIPTION	Excellent	Good	Moderate	Poor	↑ – ↓
UNIT 2 EXECUTION PROJECTS **PRE-REQUISITE PROJECTS**	Management's assessment of current performance and risk to Unit 2 Refurbishment Execution.				Managements assessment on the current performance trend.

APPENDIX 11: PHOTO CATALOGUE

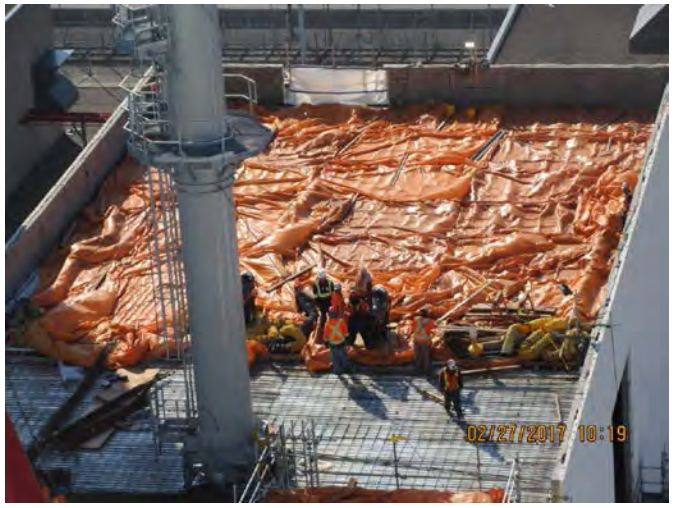
PROJECT

Heavy Water Storage Facility

Completion of Building Envelope

Installation of Landing Scrubber Stack

Installed Pipework



Maintenance (Heating) of Laid Concrete

APPENDIX 11: PHOTO CATALOGUE

PROJECT

3rd Emergency Power Generator

Installation of External Cladding

Roof Concrete Pour

Containment Filtered Vented System

Installation of Exhaust Stack

Filed: 2017-03-17
EB-2016-0152
J2.10 Attachment 1 Page 24 of 25
Period Ending: December 2016

APPENDIX 11: PHOTO CATALOGUE

Filter House Interior

PROJECT

Re-tube Waste Processing Building

Installation of Waste Tooling System Platform

Structural Steel Installation

Re-tube Waste Storage Building
(non-Refurbishment funded)

Electrical Room – Roof Pour

T20 Line and Load Terminations

Filed: 2017-03-17
EB-2016-0152
J2.10 Attachment 1 Page 25 of 26

APPENDIX 11: PHOTO CATALOGUE

PROJECT

Other On-Site Projects

Vault Prep - Installation of Bulkheads

Completed Work Control Centre

Breathing Air Installation

BURNS McDONNELL

Independent Oversight Report on the Darlington Refurbishment Project

SUBMITTED TO:

Darlington Refurbishment Committee of the Board of Directors for Ontario Power Generation

March 9, 2017

Executive Summary

OPG Management's March 9, 2017 report ("Management Report") to the DRC affirms its forecast for the Darlington Refurbishment Project ("DR Project") remains within the overall RQE control budget of C$12.8 billion and P90 schedule duration of 112 months. The Unit 2 portion of OPG's high-confidence budget is C$3.417 Billion (including C$677 million of contingency) based on an execution duration of 40 months. The DR Project's Execution Phase is currently nearing conclusion of Segment 1, during which the Unit 2 vault is being prepared for its rehabilitation. As of this writing, the DR Project is a net +5 days ahead of the working schedule's critical path since Breaker Open on October 15, 2016. After OPG's Defueling gained 26 days to critical path, 21 days have been lost [redacted] OPG's schedule metrics have significantly improved, allowing the DR Team to identify and mitigate issues, and OPG has increased field oversight in light of early performance, safety and quality trends. Assurance groups continue to be effective in identifying issues.

The Burns & McDonnell/Modus External Oversight Team ("EO Team") has identified certain issues that could have an impact on the Project if they are not addressed, including:

- SNC/Aecon's issues with vault preparation work need to be understood so that lessons learned can be incorporated in future work evolutions;
- [redacted]
- OPG's project controls focus since Breaker Open has been tracking schedule earned value; the team is refocusing on cost forecasting, including tracking the velocity of contractor costs and adverse performance trends, the effectiveness of which needs to be assessed;
- Commercial challenges in Refurbishment and F&IP projects have arisen early in the DR Project which could impact the contractors' momentum and distract OPG's and the vendors' management teams.

It should be noted that the data cut-off date for our report is February 17, 2017. While the Management Report to the DRC accurately reflects the status of the DR Project as of January 31, 2017, some data points differ from those used by the DR Team, as they reflect performance for the first 3 weeks in February.

Evaluation of DR Project Status

Key DR Project Status Indicators

Schedule Performance

	Planned	Complete	Ahead/Behind	SPI	CPI
Total Project	23.4%	19.0%	(123,876)	0.81	N/A

OPG defueled the reactor 26 days ahead of the working schedule though the post-defueling activities resulted in the DR Project losing 21 of those 26 days to date, and performance trends suggest that the bulkhead installation may further challenge the schedule. While the critical path is as of this writing, 5 days ahead, near or non-critical path work has fallen behind by 123,876 hours, with the current composite execution SPI at 0.81; RWPB, as discussed below is the largest contributor. SNC/Aecon will likely drive the critical path schedule until the reactor is fully refurbished in 1Q 2019.

Weekly schedule adherence metrics have shown a persistent problem, with causes ranging from field productivity, late construction work packages, field initiated changes and late reporting of earned value. The DR Team has instituted additional oversight of the critical path work to validate readiness with a goal of raising weekly adherence to 90% of scheduled activities.

Cost Performance	The DR Team has not exceeded the 4-unit Project control budget of $12.8 billion or the Unit 2 budget of $3.4 billion (including $677 million of contingency). Overall, the DR Project is underspent by $59 million which is split between OPG functions (-$32M) and contractor performance (-$27M). To date, contingency draws have totaled a net [redacted]. Though OPG remains resolute in doing so, the vendors' actual hours are not currently being collected for purposes of forecasting based on field productivity.
Vendor Performance	<table><tr><th>Vendor</th><th>Planned</th><th>Complete</th><th>Ahead/Behind</th><th>SPI</th><th>CPI</th></tr><tr><td>SNC/Aecon (RFR)</td><td>20.6%</td><td colspan="4" rowspan="3">[redacted]</td></tr><tr><td>ES Fox (BOP/SDLU)</td><td>29.7%</td></tr><tr><td>SNC/Aecon (TG)</td><td>40.7%</td></tr></table>
SNC/Aecon *Critical Path or Near Critical Path Work*	[redacted] SNC/Aecon's initial critical path work has been affected by discovery work, equipment and field execution issues. The bulkhead installation began on January 27 and is currently scheduled to complete on March 22, which is a key milestone. [redacted] From August 2016 to February 2017, the RWPB has lost [redacted] and approximately [redacted] against its target price estimate. Engineering, which was planned to complete in 3Q 2016, is ongoing and has [redacted] of remaining work. In mid-November, OPG challenged SNC/Aecon to identify its recovery plan for RWPB. [redacted] SNC/Aecon's milestone for completing RWPB is July 31, 2017 is at risk, and further slippage could impact the critical path for Refurbishment. [redacted] SNC/Aecon's work on the Turbine Generator has generally tracked to its schedule and is not a concern at this time.
ES Fox *Critical Path or Near Critical Path Work*	[redacted] ES Fox's management has implemented an improvement plan that addressed all aspects of its performance—safety, quality, schedule management and resources. While ES Fox recovered its schedule, it was not without added cost. With Segment 1 concluding, this is an opportune time to examine future work to ensure that ES Fox can sustain this improvement within budgeted cost and schedule.
Project Controls and Risk Management	The OPG Project Controls team's improved reporting has increased visibility to problem areas. [redacted] The DR Team now is increasing its cost focus to bolster its forecasting. The team is rolling-out additional cost tracking functionality and increasing its use of EcoSys as a forecasting tool. A critical

	component to accurate forecasting depends on obtaining vendors' actual hours and capturing field productivity rates. Obtaining this data will greatly increase the efficacy of OPG's cost forecasting. Risk Management activities are proceeding well with increased senior management support and visibility to successful mitigation of risk events. Contingency tracking and forecasting based upon outstanding risk needs to be validated. The EO Team has some concerns which management is addressing regarding the roll-up of contingency information from the granular to the summary level, which we will address prior to the next DRC report. The risk team is currently improving its ability to forecast potential future contingency draws in order to analyze the remaining contingency.
Construction Checkout and Testing	Vendor performance of the Construction Completion Declaration ("CCD") process and turnover for OPG commissioning/return to service is improving through consolidating turnover packages, performing early reviews of CCD documentation, and assisting vendor conformance. Attention is currently focused on near term (2 week) CCD and turnover requirements with the objective of expanding readiness to a 4+ week window.

Project and Program Assurance

The DR Team's Performance Assurance Group ("PAG"), Enterprise Risk Management and OPG Internal Audit ("IA") are executing robust plans for assurance activities. PAG and Quality Assurance are currently focused on increasing vendor focus on field supervision, safety and quality, and interacting directly with vendors to instruct them on avoiding safety and quality issues. ERM and IA continue to focus on program-level risks and vendor performance. IA is currently planning to audit barriers to field performance through direct surveillance.

OPG Project Team

The DR Team has reacted to the early challenges to critical path by increasing pre-critical path validation and preparation. OPG management has instituted more granular pre-execution reviews with the vendors and integration with key OPG personnel. OPG has also initiated a program to improve accountability which focuses on communications, teamwork, and expectations. This program's focus is on understanding responsibilities, schedule adherence, stakeholder interfaces, and increasing visibility of safety requirements and the potential consequences of non-compliance.

Project Risks and Strategic Considerations

The EO Team offers the following analysis of certain forward-looking risks and strategic considerations that could impact the P90 high-confidence schedule.

Risk Area	EO Team Observations
Performance Reporting	[redacted] The OPG team now needs to increase focus on cost reporting so that Estimates at Completion ("EAC") are accurate, impact costs are transparent and adverse trends are timely identified. Currently, cost forecasting is a *following,* rather than a *leading* indicator as it relies

	on receipt of actual invoices weeks after the work has been performed. The most critical cost trend on the DR Project requires forecasting the number of craft workers needed to accomplish the work, which is calculated based on the vendors' actual hours compared to their budgeted hours. The DR Team's forecasting needs this data to accurately track field productivity trends and to fully utilize the EcoSys cost toolset. Taking these steps will further enhance the accuracy of impacts of newly-identified risks, ongoing commercial issues or other factors that influence EAC. While the weekly progress metrics have improved such that OPG now has clear line of site into performance issues, cost impacts are not being concurrently assessed with the same rigor. Without this balance, OPG's management focus is weighted towards schedule over cost. That may be appropriate at this time, particularly since the critical path is a greater risk, but OPG needs to arrive at a balance of cost and schedule considerations to inform its decisions going-forward.
Commercial Management and Change Management	Effective commercial management involves ensuring the company's contractual position is maintained and asserted as necessary, while also protecting the project management team's focus on the work in the field. Doing so requires having sufficient talented resources in place and a high-level of efficiency in systems used to manage this effort. As anticipated, there has been a significant increase in the volume of work associated with documenting and tracking potential commercial issues. The DR Team currently lacks a formalized or standard way to initiate, respond to and track correspondence notices with vendors; track contractual milestones; monitor schedule and performance issues; or provide prompt notice of vendor deficiencies. Management should address establishing a methodology for bounding potential outcomes for commercial claims and disputes. The Change Management process is in place and seems to be working—however it is not currently automated, which is standard practice for a project of this size and complexity so that there is visibility to in-process changes. We note that the VP of Commercial Management has recognized many of these gaps and has initiated changes in processes and added resources to meet these challenges.
SNC/Aecon Performance	[redacted]
F&IP Projects	The Emergency Power Generator 3 ("EPG3"), Containment Filter Venting System ("CFVS") and D2O Storage Facility each continue to miss targeted schedule dates and cost projections. These projects continue to drain resources from Refurbishment, OPG/vendors' management attention and threaten to utilize additional program contingency for their completion. Moreover, there are trends observed in the vendors' management of those projects and other past F&IP projects that must be eradicated in Refurbishment.

UNDERTAKING J3.1

Undertaking

To provide the 2017 Corporate Scorecard.

Response

The 2017 Corporate Scorecard was approved by the OPG board of directors on November 10, 2016, and communicated internally January 2017. The witness indicated in error that it had not yet been approved by the board of directors.

A copy of the 2017 Corporate Scorecard is provided in Attachment 1.

Corporate 2017 Balanced Scorecard				
	Key Performance Indicators	**Threshold**	**Business Plan**	**Stretch Target**
10%	**Social Licence** - Through building and maintaining public trust, positive indigenous relations and an engaged workforce			
10%	**AIR**: All Injury rate	0.49	0.37	0.31
	Safety focus areas: o Continuing to develop and implement materials, initiatives and model behaviours that will progress and imbed the iCare Enough to Act for Safety culture o Enhance field oversight to monitor compliance to our safety initiatives and programs including contractors, with a focus on the Darlington Refurbishment Project o Continue to advance the Total Health culture in OPG through the implementation and execution of initiatives that will promote employee attendance, mental health and the adoption of healthy behaviours and lifestyles	As determined by CEO		
	No significant events that impact OPG's reputation			
35%	**Financial Strength** - Through regulated asset revenue and expansion of our core business, risk management, commercial focus and financial flexibility			
20%	**EBT**, excl. nuclear waste management segment ($M)	675	875	1075
15%	**Operating OM&A Expenses** – Total OPG ($M)	2675	2550	2425
15%	**Operational Excellence** - Through efficiencies and optimized asset management in a safe and environmentally responsible manner			
15%	**Production** – Total OPG adjusted for SBG (TWh)	70.3	72.4	74.6
40%	**Project Excellence** - Through delivering project results on time and on budget and industry leading project management			
10%	**Refurbishment Project Cost** – 2017 actual expenditures ($M) as a percentage of approved 2017 budget	100%	97.5%	95%
5%	**Refurbishment Unit 2 Critical Path Execution** – Commencement of Feeder cabinet removal (Milestone #A1012)	5-Aug-17	26-Jul-17	28-Jun-17
10%	**Refurbishment Unit 2 Critical Path Execution** - Progress of critical path on December 31, 2017	All Bellows Severed (Milestone #A1127)	50% of End Fittings Removed (Milestone #A1056)	400 Pressure Tubes Removed (Milestone #A1058)
5%	**Pump Generating Station** In-Service and within budget	1-Jun-17	1-Apr-17	1-Mar-17
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5%	**Total In-service Capital -** not including major projects otherwise on scorecard (DRP, [redacted] and PGS)	$578 +/-10% to +/-15%	$578 +/- 3% to +/-10%	$578 to +/- 3%
100%				

These measures form the basis on which our overall Corporate performance will be assessed, but the scores against these measures and overall Corporate Score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

UNDERTAKING J3.2

Undertaking

To provide the quantum/percentage of planning costs for future units.

Response

The detailed budget estimates for Units 3, 1 and 4 are yet to be developed, and OPG is not requesting approval for in-service amounts for any of the costs for these units in this application. Ultimately, the approved estimates for future units may differ from the estimates provided in this undertaking response, and such approved estimates will be the basis for future in-service additions related to these units.

Based on current information, OPG estimates that, on average, 13% of the costs for Units 3, 1 and 4 are planning costs. These estimates are as a percentage of the forecast costs for these units, excluding interest and contingency.

UNDERTAKING J3.3

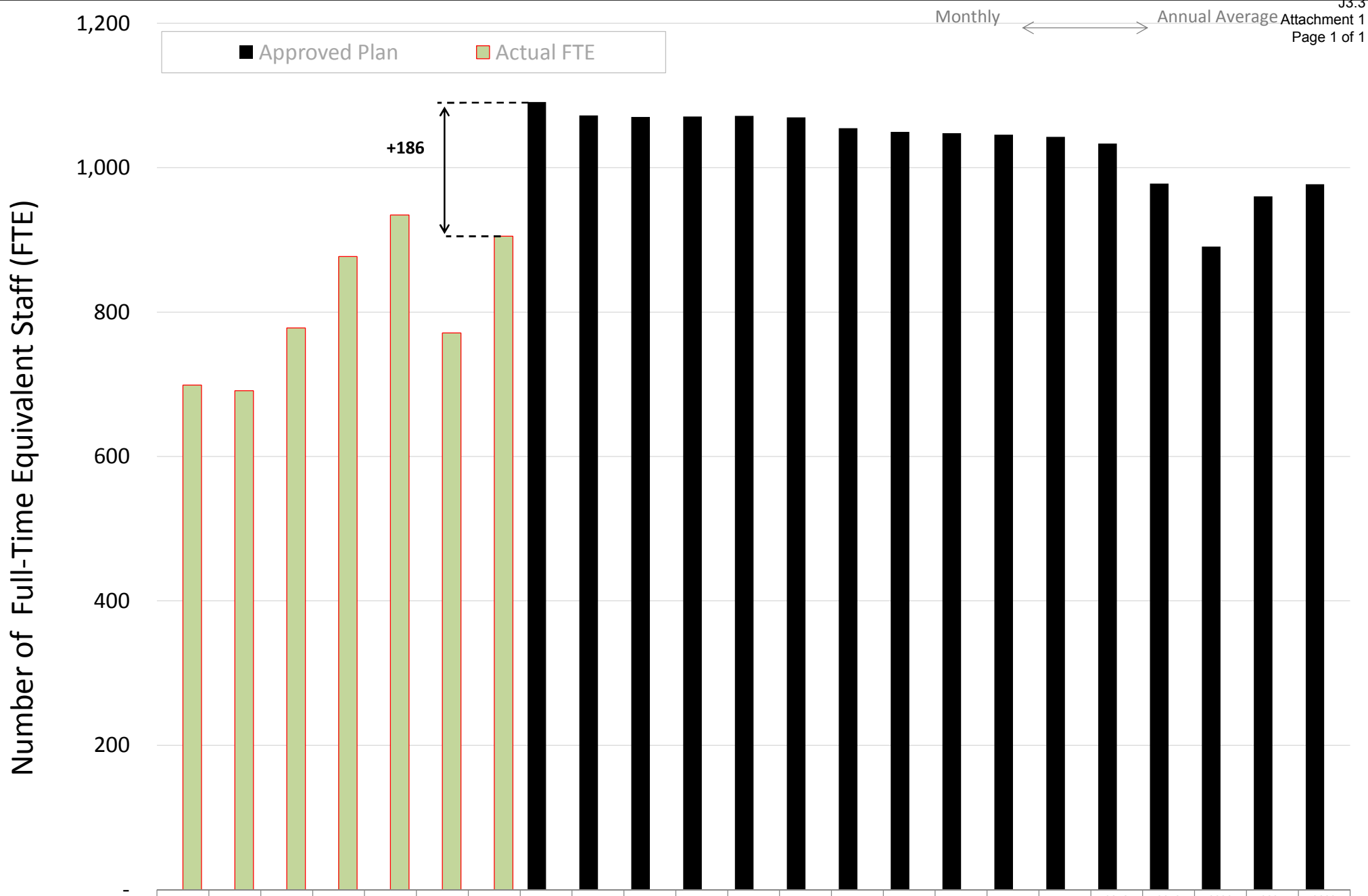
Undertaking

To provide an updated resource plan, if available.

Response

The request was to provide the current status of the actual staff levels versus the planned staff levels in a similar chart to that provided in response to Ex. L 4.3-2 AMPCO-087, part d). The chart as of January 2017 is provided in Attachment 1. Note that since August 2016, the staffing gap has been reduced by approximately 180 full time equivalents.

J 3.3 Attachment 1 : January 2017 Full Time Equivalents Against Staffing Plan at RQE



	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2018 Avg/mos	2019 Avg/mos	2020 Avg/mos	2021 Avg/mos	2022 Avg/mos
Approved Plan								1,091	1,072	1,070	1,071	1,072	1,070	1,055	1,050	1,048	1,046	1,043	1,033	978	891	960	977
Actual FTE	699	691	778	877	934	771	905																

UNDERTAKING J3.4

Undertaking

Reference: Project and Program Contingency in L4.3-2 AMPCO-72

To provide what the numbers are for the target cost contingency for the RFR and the Turbine Generator EPC including escalation and interest.

Response

The request was to provide the approximate total contingency, including interest and escalation, within the RQE estimate of $12.8B, should the $371M contingency within the RFR contract and the $28.4M contingency within the Turbine Generator EPC contract be added to the RQE contingency of $1.706B (2015$) (which is equivalent to $2.006B when interest and escalation is included).

OPG has made a simplifying assumption that the RFR and Turbine Generator EPC contingency would be flowed in a similar manner to OPG's contingency.

The $371M RFR contingency is in 2015$. Applying the same ratio of interest and escalation as per OPG's contingency, this would be equivalent to approximately $436M ($371M x 2006/1706), including interest and escalation.

The $28.4M Turbine Generator EPC contingency amount is in escalated dollars, therefore only interest needs to be applied. Ex. D2-2-8 Att. 1 p. 27 shows total interest and escalation in OPG's RQE estimate to be $2,371M, with $1473M being interest and $898M being escalation. Using a similar ratio of interest to escalation, to adjust the $28.4M of Turbine Generator EPC contingency for interest only yields $31.5M or approximately $32M.

Therefore, the approximate total, including interest and escalation, when OPG's contingency and the contingency in the RFR contract and the Turbine Generator EPC contract are added is estimated at $2474M ($2006M + $436M +$32M), or 19% of the $12.8 Billion total estimate.

UNDERTAKING J3.5

Undertaking

To provide the methodology to get to the Unit 2 in-service amounts at an alternate P level, if there is one. If not, advise that there is no methodology.

Response

The methodology used in OPG's response to Ex. L-4.3-5 CCC-018, part b) to prorate the contingency amount for Unit 2 by the ratio of the P50 contingency amount to the P90 contingency amount for the overall DRP, can also be used to estimate the revised in-service amount for Unit 2 at other confidence levels, e.g. P70.

This methodology, while providing a reasonable approximation of a revised in-service amount at any particular revised confidence level, would not yield an accurate in-service amount. An accurate in-service amount can only be generated by determining the contingency cash flow at the revised confidence level, apply it over the base estimate, and re-doing the detailed escalation and interest calculations.

UNDERTAKING J4.1

Undertaking

Please provide the unspent and not committed amounts for DRP that OPG is asking for in this application, after the financial statements are available from the March Board meeting.

Response

Of the total in-service and OM&A amounts for the DRP for which OPG is seeking recovery in this application, the total amount which is unspent and not committed is $2,130 million as of December 31, 2016.

The $2,130 million is determined after taking into account amounts previously approved by the OEB (refer to Undertaking J2.1), actual expenditures to December 31, 2016, plus accruals and commitments, the project approvals sought as set out in OPG's Second Impact Statement (Ex. N 2-1-1) and the 2016 OM&A bridge year budget.

UNDERTAKING J4.2

Undertaking

To provide the cost of turbine generator controls work for Unit 2.

Response

Please see Tr. Vol. 4, p. 42 lines 4-10.

UNDERTAKING J4.3

Undertaking

How much contingency has been drawn down since U2EE, and also from the Program in total to date?

Response

Please refer to the response to Undertaking J2.10, Attachment 1, Appendix 5B, p. 15 (confidential), in particular, the column entitled “Drawdowns against U2EE” and and the corresponding note. The amount drawn down from the overall program contingency is the total shown at bottom of that column (see note 2).

UNDERTAKING J4.4

Undertaking

To provide:

(1) For Project Management/Oversight Costs, 2016 plan, 2016 actuals, and 2017 plan, inclusive and exclusive of Owner support services (OSS) (and if not, why not); and
(2) For OPG's all-in labour DRP costs, 2016 plan, 2016 actuals, and 2017 plan.

Response

Chart 1 provides the requested information for 2016 plan, 2016 actuals and 2017 plan and expands on the table in JT 1.02 by including OPG Project Management/Support Costs in addition to OPG Oversight costs. Costs shown are for the entire DRP. The first column is OPG regular, temporary and augmented staff only. The second column also includes managed task services (MTS), such as owner support services and similar contracts.

The 2016 under-expenditure relative to plan reflects timing variances across several categories, the largest of which include radiation protection services, procurement oversight and return to service programs.

Chart 1: OPG Project Management and Oversight Labour and MTS Costs

#	Bundle / Category	2016 Actual DOY $M		2016 Plan DOY $M		2017 Plan DOY $M	
		No MTS	With MTS	No MTS	With MTS	No MTS	With MTS
1	Retube & Feeder Replacement	6	19	9	22	9	9
2	Turbine Generators	3	5	3	5	3	4
3	Balance of Plant	14	18	8	15	8	12
4	Fuel Handling/Defueling	2	3	3	6	3	5
5	Steam Generators	1	1	1	1	1	1
6	**Subtotal Major Work Bundles**	**26**	**46**	**25**	**49**	**25**	**31**
10	Project Execution	13	23	15	25	18	25
11	Contract Management	2	4	3	5	3	5
12	Engineering	19	26	21	22	22	23
13	Managed Systems Oversight	3	3	3	3	3	4
14	Planning & Controls	7	12	6	8	6	7
15	Nuclear Safety	3	5	4	9	4	7
16	Program Fees & Other Support	5	5	5	8	5	8
17	Supply Chain	3	3	4	11	4	11
18	Work Control	9	10	7	7	8	8
19	Ops & Mtce	37	44	41	64	61	70
20	Early Release 3	-	-	-	-	-	-
21	Early Release 4	-	-	-	-	-	-
22	**Subtotal OPG Functions**	**101**	**135**	**108**	**160**	**134**	**167**
28	**Total Project Management / Oversight**	**127**	**181**	**133**	**209**	**159**	**198**
A	Oversight (per JT 1.02)	60	97	58	97	63	80
B	OPG PMT/Support	67	84	74	112	96	118

DOY$M = millions of dollars of the year, i.e. including interest and escalation.

Row numbers shown in green are Oversight and row numbers shown in white are OPG Project Management/Support costs.

UNDERTAKING J4.5

Undertaking

To augment the table provided in Ex. L-4.3-1 Staff-055 Attachment 1, p.13, by a) breaking out of line 13 for F&IP and SIO projects; b) Adding a new column with contingency breakdown by project line items; and c) Adding a new column with the planned in-service date for each line item.

Response

a) There are no F&IP and SIO projects included in the referenced U2EE cost summary. Please refer to Ex. D2-2-10, Tables 2 and 3, and the updates to these tables provided in response to Undertaking J2.6 for in-service dates for F&IP projects and SIO.

b) and c) Chart 1 below shows the breakdown by project line item of the total of $677.5M contingency at establishment of the U2EE and the planned in-service dates of the projects within the Project Bundles. All project bundles are fully in-service by February 2020.

Although OPG has allocated contingency on a project bundle basis and to the functions as set out in Chart 1, OPG's reiterates that contingency was calculated on a program basis and that:

(i) it is committed to placing Unit 2 in-service at or below the forecast in-service amount of $4.8B;

(ii) during the Unit 2 refurbishment, should the contingency allocated to an individual project bundle or function not be fully utilized, OPG will use that contingency as required, e.g. to off-set the "over-utilization" (i.e. based on the allocation provided herein) of contingency on another individual project bundle or function; and

(iii) should contingency allocated to Unit 2 not be fully utilized, OPG will carry-over that unutilized contingency on Unit 2 to be potentially utilized on the refurbishment projects of future units in order to deliver the 4-unit refurbishment program within the $12.8B budget.

Chart 1 – U2 Cost Summary Updated with Contingency Breakdown and I/S Dates

#	Division	RQE	Current U2EE	Variance from RQE	%	U2EE Contingency Breakdown	Planned In-service date
1	NR - Retubing & Feeder Replacement	1,143,965	1,148,041	4,077	0%	115,585	Feb-20
2	NR - Turbine Generator	226,164	228,012	1,849	1%	59,750	Feb-20
3	NR - Balance of Plant	165,731	186,299	20,568	12%	65,163	Feb-20
4	NR - Fuel Handling	21,498	16,448	(5,050)	-23%	10,242	Feb-20
5	NR - Defueling	31,544	35,978	4,434	14%	2,209	Feb-20
6	NR - Steam Generator	53,313	54,537	1,224	2%	16,533	Feb-20
7	NR - Specialized Projects	85,593	86,656	1,063	1%	5,272	Feb-20
8	NR - Shutdown, Layup and Services	83,371	76,354	(7,017)	-8%	50,745	Feb-20
9	NR - Unit Islanding	57,731	61,058	3,327	6%	2,742	Feb-20
10	NR - Waste Disposal	7,713	7,713	-	0%	-	
11	NR - Refurbishment Support Facilities	35,478	36,382	904	3%	11,035	Feb-20
12	**SubTotal Bundle Projects**	**1,912,101**	**1,937,478**	**25,378**	**1%**	**339,276**	
13	NR - F&IP + SIO Projects						
14	**SubTotal Campus Plan Projects**					**-**	
15	OPG Functions + Ops & Maintenance	791,583	802,114	10,532	1%	35,771	Feb-20
16	**SubTotal Functions**	**791,583**	**802,114**	**10,532**	**1%**	**35,771**	
17	**SubTotal Base Costs**	**2,703,684**	**2,739,592**	**35,910**	**1%**		
18	Total Contingency	689,530	677,453	(12,078)	-2%		
19	Program Discrete Risk, Cost & Schedule Contingency					302,406	
20	**SubTotal Contingency**	**689,530**	**677,453**	**(12,078)**	**-2%**	**677,453**	
21	Nuclear Refurbishment Program	3,393,214	3,417,045	23,832	1%	677,453	

UNDERTAKING J5.1

Undertaking

To provide the post-filing planning costs related to Unit 2 either incurred or forecast to be incurred.

Response

OPG estimates that, from 2016 onwards, approximately $295M of planning costs (excluding interest or any contingency amounts) have been or will be incurred related to Unit 2.

UNDERTAKING J5.2

Undertaking

To update the table at L-4.3-5 CCC-018, part b) for U2EE, and to validate and explain any variance to the math used by Mr. Mondrow.

Response

OPG corrected the math used by Mr. Mondrow on the transcript. See Tr. Vol. 5, p. 54, lines 13-26.

The Unit 2 Execution Estimate (U2EE) cannot be estimated at the P50 level by updating solely for the contingency amount because other elements in addition to contingency have changed from RQE to U2EE (see Ex. L-4.3-1 Staff-055 Attachment 1, p. 13). The cost flow profile also changed, which affects cumulative interest costs.

The U2EE is provided at Ex. L-4.3-1 Staff-055, Attachment 1, p. 13. The high confidence Unit 2 contingency amount has decreased by $12M from $689.5M at RQE (November 2015) to $677.5M at U2EE (August 2016). Applying the same approximation methodology utilized in Ex. L-4.3-5 CCC-018, part b), the contingency amount at the time of U2EE at the P50 confidence level can be estimated by prorating the P50 and the P90 contingency estimates (those at the time of RQE are utilized for the pro-rating), which would yield $563.9M ($677.5M x ($1.420B/$1.706B)), including interest and escalation. Therefore, the estimated reduction in the U2EE contingency amount would be approximately $114M ($677.5M less $563.9M).

Chart 1 provides an estimate of $4,735M for the U2EE in-service amount at an approximate P50 contingency level.

Chart 1

$M	2017	2018	2019	2020	2021
As filed on May 27, 2016 – In-Service Additions (1)	374.4	8.9	0.0	4,809.2	0.4
Updated to remove D2O Project (per Ex. N2-1-1) and for U2EE In-Service Amounts	8.5(2)	8.9	0.0	4,849(3)	0.4
Estimated In-Service Additions with Unit 2 EE In-service Amount including P50 Contingency	8.5	8.9	0.0	4,735(4)	0.4

Note (1) See Ex. D2-2-10, Table 5

Note (2) OPG's Second Impact Statement Ex. N2-1-1 removed the forecast in-service amount of $365.9M in 2017 associated with the D2O Project.

Note (3) Ex. N1-1-1 Attachment 1, p. 17. Although OPG's Unit 2 EE estimate update resulted in a new interim in-service amount projection of $4,849M in 2020, this is a point-in-time estimate and OPG is not changing its in-service amount forecast at this time (see Tr. Vol. 4, p. 58, lines 22-28 and p.59, lines 1-7).

Note (4) Calculated as $4,849M U2EE in-service amount less $114M estimated reduction in contingency moving from P90 to P50 level, described above

UNDERTAKING J5.3

Undertaking

Reference: J4.3

To provide the draw-downs that remove from contingency, as well as any amounts that have replenished contingency for risks that have passed that did not bear as at end of January 2017 (i.e. gross and net movements in contingency).

Response

Please refer to the response to Undertaking J2.10, Attachment 1, Appendix 5B, p. 15 (confidential), in particular, the columns entitled “Drawdowns against U2EE” and “Transfers to General Reserve” and their corresponding notes.

UNDERTAKING J5.4

Undertaking

Reference: D2-2-3, p. 4

For each contractor in chart 2 of D2-2-3, to advise the dollar value of the contracts under the auspices of that contractor in respect of the Unit 2 in service amounts, or in other words, for the in service amounts in play in this proceeding, to advise the dollar value that is the responsibility of each prime contractor including for the early in service projects, F&IP, and SIO contractors.

Response

Chart 1 represents the amount of contractor costs, related to the early in service projects, F&IP and SIO, and Unit 2. OPG maintains records on contractor costs for the DRP on a life cycle basis. Thus, the contractor costs included in Chart 1 include amounts for which OPG is seeking approval in this application as well as amounts approved under previous applications consistent with Undertaking response J2.1.

Chart 1: Contractor Value in Current and Previous Approvals

Vendor	Value for which Approval is Sought in EB-2016-0152 or was received in Prior Applications ($ millions)
SNC Aecon	1,615
Alstom	115
GE Hitachi	23
ESMSA - ES FOX	609
ESMSA - B&M	98
BWXT / Candu	35
BWXT	15
Total	**2,510**

UNDERTAKING J5.5

Undertaking

Why is the bleed cooler inspection/repair for the Steam Generators work package only required for Unit 2?

Response

The decision to perform the Unit 2 Bleed Cooler Inspection/Repair during the Unit 2 refurbishment was endorsed by the Program Scope Review Board as a risk mitigation measure and because of timing.

None of the bleed coolers in any of the Darlington units has ever been inspected, and it was deemed prudent to inspect these bleed coolers in all units at the earliest opportunity, with the Unit 2 refurbishment outage being the first scheduled outage at the time of the decision. There is a low probably risk that the bleed cooler tube bundles, which are long lead procurement items, will need replacement. Replacement is most effective when the bleed cooler is already in a drained and dried state during refurbishment. The inspection results will inform the risk of tube bundle replacement in subsequent units.

The current plan for the remaining three Darlington units is to complete the inspections during upcoming planned outages. Should prior units' inspections indicate that tube bundle replacement may be required (considered a very low probability), the replacement will be scheduled in planned outages or refurbishment outages depending on timing.

UNDERTAKING J5.6

Undertaking

With reference to the projects listed in J2.9, to provide an explanation as to the nature of the projects and why a project will come in service before Unit 2, with Unit 2, or spread across all units.

Response

Please refer to OPG's response in J2.9.

UNDERTAKING J5.7

Undertaking

To provide an updated risk register.

Response

An updated risk register as of March 7, 2017 for the DRP is filed as Attachment 1 (confidential).

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Balance of Plant -																	
15128	Design cost increase and schedule delays due to the additional stress analysis re-run	ASDC stress analysis resulted in several nodes not passing as per Code requirements. Additional analysis (NB3200, sensitivity analysis, analytical methods) may be required in order to ensure a clean pass of the stress analysis mandatory for the TSSA registration of the modification. if the risk occurs, then cost and schedule of the project will be impacted.		Active	Katie Stewart	Doina Idita	03-Mar-17	Accept	01-Sep-17	4	1	4	16	4	1	4	16
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13263	PHT & Aux - PHT Pumps Will Require Repairs [window 048]	Event: PHT Pump (2-33120-P3) may require repairs Cause: Due to age of pump, and inability to inspect prior to refurbishment Impacts: Cost and schedule impacts Background: During DNRU2 a single PHT Pump (2-33120-P3) will be inspected to determine the condition of the pump and if any contingency repairs are required. The risk is that the 2-33120-P3 is in poor condition and will require full repairs. This will lead to inspections of 2-33120-P1/P2/P4 and potential additional repairs. This would also impact the scope for the remaining refurbishment unit outages.	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	02-Oct-17	2	2	5	10	2	2	5	10
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13641	PHT & Aux - Risk of Project Delays due to Conflicting Work in PHT Pump/Motor Room [Window 48]	The risk is that other work (such as the PHT Pump Motor Installations) will push the execution window for the PHT pump inspection/overhaul work. Any operation of the gantry crane and high rad work in the RMD will cause interruption of other work. Therefore, there is has a high chance of other work affecting the PHT Pump inspections, coupling removal/installation (Mech mtc. or other contractor), seal removal/installation (P&M), motor removal (P&M), and pump contingency overhaul.	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	17-Jun-17	2	1	5	10	2	1	5	10
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15155	Schedule of VVRS impacted by Breathing air	Event: Breathing air can cause delays to the start of vvrs. Cause: Delays from JV. Impact: SCHEDULE IMPACT,COST IMPACT Background: Present schedule is not accounted for manpower requirements i.e. 24/7. schedule of breathing air has an impact on the VVRS commissioning.	4	Active	Katie Stewart	Amanjot Singh	01-Mar-17	Accept	18-Mar-17	3	2	3	9	2	1	2	4
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15156	Operation resources support required 24/7 for vvrs commissioning	Event: 24/7 window support from operations may not be available. Cause: Due to defueling advance resources have been tied up in other ongoing projects. Impact: Additional cost will incur and delay to critical path. Background: window 137 requires Operation resources support required 24/7 for vvrs commissioning.	4	Active	Katie Stewart	Amanjot Singh	01-Mar-17	Monitor	15-Mar-17	3	2	3	9	2	1	2	4
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15157	Duration for Commissioning could be longer then planned	Font Size Event: bypass commissioning may take longer than expected Cause: Due to FOAK work Impact: Schedule delays Background: VVRS is a first of a kind project . The by pass commissioning can take longer then expected because it has not been done before. This could have a major impact on the project schedule.	4	Active	Katie Stewart	Amanjot Singh	01-Mar-17	Monitor	18-Mar-17	3	2	3	9	2	1	2	4
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13295	[Window 532] Risk of Fire Protection Emergent Repair Scope	DSRs IP1220-14, IP1300-1, and IP1220-3 are DSRs to perform assessments. Should deficiencies be found during these inspections/assesssments, there is a generic contingency DSR for any work required in Engineering/Testing Scope. Currently, this DSR does not carry any funding to perform the work.	3	Active	Oweis Chohan	Oweis Chohan	01-Feb-17	Monitor	09-Jan-17	4	2	2	8	4	2	2	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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13295	[Window 532] Risk of Fire Protection Emergent Repair Scope	DSRs IP1220-14, IP1300-1, and IP1220-3 are DSRs to perform assessments. Should deficiencies be found during these inspections/assesssments, there is a generic contingency DSR for any work required in Engineering/Testing Scope. Currently, this DSR does not carry any funding to perform the work.	5405	In Progress	Fire Protection Penetration/Construction Joint Field Inspections	Completion of the final fire penetrations and construction joints is required to assess the extent of repair scope. The first action is to complete the inspections TCD Aug 15. Upon completion of tyhat activity, the action ID will be updated to status when Engineering will complete the inspection analysis to confirm repair scope. That TCD will be established once the inspection reports are generated. Update : OPG Field engineering providing the inspection service. Commencing Jan 2016. Expected finish, first quarter 2016. Inspection analysis ongoing, Update June 29/26 - Field engineering was instructed to perform further analysis of high risk rooms. Expected completion on July 15th 2016. This has pushed the documentation exercise into September 2016. IIP due in December 2016 for documentation. Update Sept 14/16 : Field engineering now complete their further analysis. Documentation has slipped to completion of Oct 7/16 due to amount of drawings to be created. Update 3-Oct-2016: Inspection/documentation updates to be completed by November 2016. Being monitored. Update: BOP Projects to meet with OPG Design on status of IIP Fire Barriers Inspections completion (Target end of year 2016). Action plan to be developed on path forward for BOP projects Sika-Flex Fire barrier field campaign.	Ajay Upadhyaya	Oweis Chohan	31-Mar-17								

Feb 22, 2017: On-going discussions with Design for projects to obtain work-able sample sub-set of sikalfex and scope to complete SOW. Due Date above moved out to March 31 to re-assess.

Extent of penetrations/construction joints confirmed, SoW being drafted to obtain selective sampling to confirm EOC for Sikaflex. Date extended to Jan 2016 to allow for SoW finalization, contract issuance and status of sampling findings.
Update 03-Oct-2016: OPG design & Field Engineering to provide inspection reports/documentations/repair scope to OPG projects by November 2016. Selective sampling for Sikaflex firebarrier replacements to commence thereafter (Scope of work, contract issuance, etc)

Update : 03 Nov 2016
1) EP DCR implementation for 71 existing dwgs - over the next ~2 months (not required to close out IIP) – (340 hrs drafting w/contingency, 200 hrs eng) – Target completion is December 31st.

Update: 17-Jan-2017
OPG Design has completed their portion of field assessments/configuration management of fire barriers. OPG projects is awaiting their feedback now to proceed with IIP OI 024 (Sikaflex removal) - Design input is needed to generate a SOW and execute the work before July 2019 as per the IIP commitment. A meeting with design on this feedback/turnover is to be scheduled in the next week or 2 and a joint effort is establishing the SOW is its main objective.

Outage Window	Window Description
532	532 - Oil Storage Tank Inspections

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13261	PHT & Aux - R002 on 84.0 elevation may contain many hotspots [window 048]	The risk is that the room where the D2O collection tank and vent condenser heat exchagers (2-33810-HX1/2) currently contains a hot spot and may contain many more after the PHT drain. The Heat exchangers are located in Room-002 on the 84.0 elevation, at one of the lowest elevations of the station. During refurbishment, the removal of the D2O in the PHT Auxiliary system will be completed via a gravity drain, causing many particulates and radioactive particles to be drained to the lower elevations of the plant.	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	30-Jul-17	3	1	2	6	3	1	2	6

Outage Window	Window Description
048	048 - HTS Aux Drain,Purge,Outside Vault

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13347	PHT Pump Dismantling/Reassembly Tools Unavailable [Window 48]	Event: The Primary Heat Transport (PHT) Pump disassembly/assembly tools required for PHT pump inspection and maintenance may not be readily available for execution Cause: In the event of a forced outage, station maintenance would require the PHT Pump tools for seal replacement. Impact: Schedule delays Background: In the event of a forced outage, station maintenance will need to take back the PHT Pump tools for the use of seal replacement. Also, the vendor needs to confirm availability of all required tools for pump disassembly, inspections and reassembly. This will lead to a contractor stand down until the PHT Pump tools can be obtained to continue PHT pump inspections.	3	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	26-May-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13364	PHT Pump Component Procurement Uncertainty [Window 48]	Event: Cost of material procurement for the PHT Pump long lead components may be higher than anticipated/additional parts may be required Cause: Due to long lead time, and exclusion of all regulatory license approvals with class 5 estimate from the OEM Impact: cost impacts Background: The risk is that there is an uncertainty in the cost of material procurement for the PHT Pump Long Lead components (15 month lead time). Funding was approved in Phase 1 to complete the purchase of the materials but the estimate from the OEM was a class 5 and did not include all the regulatory license approvals. There is also a risk of requiring additional overhaul parts (PHT pump parts over and above the rotating element).	3	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	12-May-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13400	EHS Project - Inability to Perform Construction Walkdown and Risk of High Number of FICs [Windows 68, 104, 105]	The risk is that there has not been a construction walkdown held for the Class 1 portion of this modification due to no planned Unit 2 outages available during the detailed design phase. The design and construction team have not been able to get into the reactor vault, therefore the design is based on available pictures and laserscans for piping layouts and supports. There is a large risk of interferences being present in the current piping runs which are not clearly visible from available pictures. There is a likelihood that there will be a high number of field initiated changes (FICs) during construction.	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	29-Jun-18	3	2	2	6	3	1	2	6
			Outage Window		**Window Description**												
			068		068 - Emergency Heat Sink												
			104		104 - Post Feeder Vault Projects												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13658	EHS - DEC Revisions due to Unavailability of Vendor Information [Windows 48, 53, 68, 104, 105]	The risk is that DEC revisions will be required due to the unavailability of vendor information. The design of the EHS piping and support structures depends on the dimension and weights of the material components (such as manual and check valves, and other items). These items will not be available until 4-6 weeks into procurement of the components, however PO's have not yet been issued for them (in progress).	2	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Mitigate	27-Apr-17	3	2	1	6	3	2	1	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9200	In Progress	EHS Follow up on Vendor Drawing Information	The design EC's may require revision if the information according to the vendor drawings for the valves are outside what was assumed in the design (eg. weight & dimensions). This action is to track and follow up on all vendor information to confirm impact to DEC's.	Katie Stewart	Hassan Baharvandy	17-Mar-17	in Progress, most of the vendor drawing are received							
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			053		053 - ESW Rehab												
			068		068 - Emergency Heat Sink												
			104		104 - Post Feeder Vault Projects												
			105		105 - Vault Projects After Feeder Removal												
14568	EHS - Parts Availability May Cause Delays during Construction [window 48, 104]	There is a risk that during construction of Emergency Heat Sink (EHS) refurbishment project, there may be delays to construction due to late delivery of materials. This risk is specific to Class 1 valves and EP pressure test tool material, and will impact the vault projects window (104).	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	20-Feb-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain, DFead Legs and Purge,Outside Vault												
			104		104 - Post Feeder Vault Projects												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

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14577	PHT & Aux: PHT Pump inspections may be more extensive than originally quoted [window 048]	PHT P3 inspections are required to be performed during unit 2 refurbishment outage to determine extend of condition (as well as gasket replacement to fix the leaks on P3). Based on the results of these inspections, the remaining pumps may require inspections and overhaul to ensure they are reliable to extended life of the unit. As per the Vendor's BOE, it is assumed that inspection will be performed onsite with the OEM present to consult with visual and NDE inspection results; and the assumption was 160 hours of vendor on-site support (i.e. 8hrs x 20days). It has become apparent that the inspections can't logically take place onsite at OPG and the RE needs to be shipped to the OEM's location in the US. There were no provision in the estimate to ship the contaminated pump RE offsite for extended condition assessment.	2	Active	Scott Guthrie	Hassan Baharvandy	07-Mar-17	Monitor	01-Jun-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13753	Risk of Procurement of Miniature fission chambers [No Window Related]	May require procurement of new miniature fission chambers or they are not fit for use.	2	Active	John Stopar	George Naguib	11-Aug-16	Monitor	31-May-17	3	1	1	3	3	1	1	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73308																	
13756	Testing of all private fire main control valves [73312]	Todays Date: 07/March/2017 (Current scope: 14 valves to test) Due to age and obsolescence of position assured open valves - there is a risk that during the testing of these valves (opening/closing) it may cause damage/failure. This was lead to project scope/schedule/cost being impacted.	3	Active	Oweis Chohan	Oweis Chohan	07-Mar-17	Accept	30-Jun-17	2	1	4	8	2	1	4	8
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73312																	
13654	ES MSA Vendor Capability/Experience	[redacted] A full resource assessment of FOX PMT and Construction resources (against Class 3 estimate FTEs) is required to confirm if current staff are adequate and what changes to staffing are required as projects enter into/out of execution during Unit 2. Also risk is tied to risk ID - 13663	3	Active	Scott Guthrie	Scott Guthrie	23-Jan-17	Mitigate	17-Feb-17	4	3	3	12	2	2	3	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

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13654	ES MSA Vendor Capability/Experience	[redacted]	6529	In Progress	ES Fox Strategic Refurb Resource Planning	This action is associated with Risk 13654 (Fox Refurb resoruce planning). Temporary management staff have been hired by Fox to complete a PMT & Contruction resource review to provide strategic resourcing options to OPG. The scope of this investigation involves assessing FTE resources (by name) against the # of FTEs assigned in the Class 3 estimates. Opportunities to build a dedicated Refurb PMT/Construction team need to be reviewed along (with under/over-allocation gaps) as Unit 2 progresses to determine options to temporarily re-allocate key Fox staff as required. This will ensure experience/continuity/value for money for subsequent unit refurb outages and help to address the current experience/quality gaps for Unit 2.	Scott Guthrie		10-Mar-17							

Weekly review meeting underway with Fox confirming progress of strategic resourcing initiative.
Mar 16/16 status: PMT Class 3 estiamte FTE allocation confirmed against current Fox PMT team. team is approx. 50% under-resourced however after Feb 2018 the PMT workload drop significantly. Fox to provide names of proposed PMT team and insert into PMT allocation curve to determine extent of underallocation post Feb 2018. Construction staff table received ~80 % complete. Construction staff allocation table drafted and review I/P.
Apr 17/16: Conceptual approval received from Gary Rose & Mike Allen wrt PMT/Construction team approach. Presentation to be revised based on feedback & final review completed week of Apr 25 prior to requesting approval from D. Reiner. Support team Scope of Work routed for approval and draft PO sent to Fox for comment. This PO will progress Fox resources/planning in a number of areas. [redacted] BoP resource has been assigned to the look ahead team, Fox and SDLU staff assignment remains pending.
May 13/16: PMT/Construction team update noted in Action 5980. [redacted]
May 30/16 Update: QA/QC resource plan committed to be p

Outage Window	Window Description
000	000 – No Window Related

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
14379	Active	Scott Guthrie	Breanne Stramenga	07-Mar-17	Mitigate	01-May-17	3 1 3 9 2 1 2 4

ID	Risk Title	Risk Description
14379	73312: Tin Whisker Cleaning - ToR Schedule Risk	Event: Relay replacements have only been done a few times at Darlington on a small scale (1-2 at a time). Cause: The volume of work (180 relays) that will need to take place. Impact: The volume of work (180 relays) may result in failed or delayed post maintenance testing, which could cause significant rework to diagnose & repair the problem.

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14379	73312: Tin Whisker Cleaning - ToR Schedule Risk	Event: Relay replacements have only been done a few times at Darlington on a small scale (1-2 at a time). Cause: The volume of work (180 relays) that will need to take place. Impact: The volume of work (180 relays) may result in failed or delayed post maintenance testing, which could cause significant rework to diagnose & repair the problem.	7596	In Progress	Class 2 Relay "Tin Whisker" Maintenance - Develop Spares Plan	Develop Spares Plan, including: 1. Investigate spare relay availability with ABB/EPRI/COG. 2. Confirm existence of 11 spares (put hands on them). 3. Clean of existing spares and subsequent verification of functionality.Meet with Station Engineering to review spares plan.	Ajay Upadhyaya	Breanne Stramenga	30-Apr-17								

Action extended to June 30/16 as OPG PM is on OCC duty until June 20/16. Current status - Tin Whiskers workplan remains on track for OPG approval by June 15/16, other areas pending review by PM upon return.
July 25 Upate: Work plan approval TCD is now July 31, and is at risk. Extended to September.
Aug 10/16 Update: Quotation received from vendors - cost is 5k per unit. Minimum order is 400 (2M$). Further engineering analysis I/P as it is estimated that the cost of a modification to replace the units will exceed the cost of spares.
Sept 28/16 - Action date updated to reflect TCD for analysis.
Oct 4/16: Pre-req workload/vendor oversight and lack of resources challenging completion date. Aug staff request being processed to bring in more project resources. Action extended to Oct 31 to allow additional staff to come into role.
Dec 29th Update: System Engineering spares recommendation will be submitted by Feb 28th, due date changed to reflect new commitment.
Mar 7,2017: System Engineering commitment missed, new due date is end of March

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD								
13853	Warranty Period Extension beyond 2 year ES MSA contractual term	Event: There is a possibility that we would need to extend the warranty period for materials beyond the 2 year timeline. Cause: The expectation is that material needs to be procured at arrived at site t-6weeks from the execution window. However, there are instances where the execution work occurs later on within the execution window, especially for work currently assigned to segment windows (131, 132, 133) Impact: Warranty may have elapsed prior to installation resulting in additional cost to cover extra warranty requirement		Active	Scott Guthrie	Kevin Tse	23-Jan-17	Monitor	16-Feb-17	3	2	1	6	3	2	1	6

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD								
14380	73312-Tin Whisker Cleaning - Resource Risk	Event: This project requires specialized OPG station resources (DCC group) to perform the work Cause: There is risk of resource availability for future units, as specialized resources are not available outside of OPG Impact: There is a schedule risk due to resource availability during work window which may cause delays.		Active	Scott Guthrie	Breanne Stramenga	07-Mar-17	Monitor	01-Feb-18	2	1	3	6	2	1	3	6

Outage Window	Window Description
000	000 – No Window Related

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ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD								
14378	73312: Tin Whisker Cleaning - ToC Relay Spares Risk [No Window Related]	Event: Significant degradation is uncovered during Tin Whisker cleaning/relay inspection; or that we fail PMT due to contact degradation missed during inspection Cause:The relay is obsolete and there are only 7 spares for ~180 relays on U2 only Impact: Spare relays will need to be purchased if results are unfavorable. This poses a significant cost risk to the project since the relays will need to be custom made.		Active	Scott Guthrie	Breanne Stramenga	07-Mar-17	Mitigate	01-Jan-18	2	2	2	4	1	1	2	2

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14378	73312: Tin Whisker Cleaning - ToC Relay Spares Risk [No Window Related]	Event: Significant degradation is uncovered during Tin Whisker cleaning/relay inspection; or that we fail PMT due to contact degradation missed during inspection Cause:The relay is obsolete and there are only 7 spares for ~180 relays on U2 only Impact: Spare relays will need to be purchased if results are unfavorable. This poses a significant cost risk to the project since the relays will need to be custom made.	7596	In Progress	Class 2 Relay "Tin Whisker" Maintenance - Develop Spares Plan	Develop Spares Plan, including: 1. Investigate spare relay availability with ABB/EPRI/COG. 2. Confirm existence of 11 spares (put hands on them). 3. Clean of existing spares and subsequent verification of functionality.Meet with Station Engineering to review spares plan.	Ajay Upadhyaya	Breanne Stramenga	30-Apr-17									

Action extended to June 30/16 as OPG PM is on OCC duty until June 20/16. Current status - Tin Whiskers workplan remains on track for OPG approval by June 15/16, other areas pending review by PM upon return.
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Outage Window	Window Description
000	000 – No Window Related

Project: Balance of Plant - 73335

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14401	AA & ICFD Replacement Staff Experience [window #21]	This risk is associated with the introduction of new tooling and processes to staff with little experience in performing the work. AA Rod Replacement has never been performed at Darlington and is new to the contractor. Horizontal ICFD is also a FIAW activity that is being performed by a vendor that has never performed the work before. In addition, discharge of flux detectors into the IFB is new to DNGS. The lack of experience is associated with the tooling/work process of replacing/discharging AA rods, assembly/installation of correct AA Rod Types and horizontal flux detector removal/install and discharge into the IFB.		Active	John Stopar	George Naguib	13-Feb-17	Mitigate	31-Oct-16	4	4	4	16	2	2	1	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.

Outage Window	Window Description
021	021 - Replace Adjuster Rods

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14206	High Dose for HFD Program [Window 73]	ALARA review has been completed and assessed the Horizontal Flux Detector Replacement Program to result in 115 Rem dose to workers. The high dose is due to hotspots in the SDS2 bunker.		Active	John Stopar	George Naguib	21-Oct-16	Mitigate	15-Dec-17	5	2	2	10	4	1	1	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8807	In Progress	HFD Process Cycle Time Validation on Mock-up	The cycle time of the HFD removal and installation processes must be validated on a representative mock-up in order to confirm that the cumulative dose has been properly estimated in the ALARA plan.	John Stopar	George Naguib	15-Dec-17	The dose target is based upon the assessed times for each sub-task as noted in the approved HFD Alara plan. The target dose for completion of this refurbishment activity is 39.4 Rem.

Outage Window	Window Description
073	073 - HFD Replacements

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13299	Radiation Protection Risks with Flux Detector Removals [Window 28, 73]	Due to the highly radioactive nature of the flux detectors, there is a possible schedule delay during execution of FD removals if a detector becomes lodged, stuck, or broken within the chopper tool. The Stern design of the chopper tool includes small contingency tooling to dislodge detectors in the case of minor issues during chopping. This tooling is designed to deal only with specific circumstances (ie. minor blockages). Darlington Reactor Maintenance has made use of a robotic assembly during removals on the outermost FD assemblies on the deck. The execution team cannot rely on this robotic tool due to the wholesale replacement strategy. The deck is far too crowded with safety related drive mechanisms to allow use of a travelling robotic assembly. The purpose of this risk is to document the possibly schedule and cost delays associated with unforseen failure of the chopping tool. EDIT 20NOV2015: This risk is also associated with HFD schedule delays due to radiological interferences with RFR.	2	Active	John Stopar	George Naguib	21-Oct-16	Mitigate	30-Nov-16	3	2	3	9	2	2	1	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6756	In Progress	Contingency Plans for HFD and VFD Replacement	This action is associated with Risk ID 14207. Contingency planning for stuck detectors during the HFD and VFD replacement windows will need to be established prior to executing the work.	John Stopar	George Naguib	31-May-17	8 Aug 2016 (J.Stopar): Two contingency planning sessions have been conducted with the ICFD Tooling supplier and experienced end users who have performed work with the tooling at Darlington, Bruce, Pt Lepreau, Wolsong and Quinshan. Workable contingency plans have been formulated and the details to achieve them are being worked on. 21 Oct 2016 (G. Naguib): OPG and vendors are working on a new strategy to cut HFDs with the chopper tool off the HFD assemblies in order to create ease of execution and contingency planning. The design efforts by Stern to complete this new strategy will begin November 2016.

Outage Window	Window Description
028	028 - Replace Vertical Flux Detector
073	073 - HFD Replacements

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11337	Reactivity Deck Training Location [No Window Related]	The risk is that current facilities are insufficient for reactivity mechanism training. In the event that the EPC contractor cannot use the existing DNGS training facility, a new facility would be required. This would cause significant cost increase to the project.	3	Active	John Stopar	George Naguib	03-Feb-17	Monitor	15-Jan-17	2	1	4	8	2	1	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1723	In Progress	Details of Risk Response Strategy for Risk #11337	Training Plans are to be developped by the EPC vendor for Flux Detectors and AAs. A station integration meeting will be conducted to ensure alignment with the vendor training plan (as shared use of the RMD mock up will be required).	John Stopar		28-Apr-17	VFD and HFD Mock-ups exist in Turbine Hall. Arrangements for shared use required. J.Stopar 30 SEP 2015 : the Unit 2 Level 1 is still under development and the execution windows for Adjusters, VFDs are being shifted. The schedule must be set before meaningful discussions can take place with the Fuel Handling Dept which is the owner of the RMD rehearsal Facility. G. Naguib 02Sept2016: Vendor has prepared training plan for Adjuster Replacement, VFD, and HFD projects. The RM Training Facility is suitable for use with the addition of interferences for a more realistic working space approach. The vendor and BOP will work together to determine the types and extent of interferences required for a realistic mockup. Further assessment of the current HFD guide tube/assembly bundle usability is ongoing. Station integration meeting has taken place and a memo of understanding outlining the Refurbishment's use of the U4 extension RM mockup has been drafted. 21 Oct 2016 (G. Naguib): HFD Mockup assessment will determine if additional location is required. The U4 extension HFD mockup does not include a full length assembly (only a single well extension). Ongoing meetings with vendor and Project will determine if further mock up construction is required. 2 Feb 2017 (J.Stopar) : ES Fox training plan review by OPG has identified gaps. Training plan is being revised.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11332	Reactivity Deck Training Location [No Window Related]	The risk is that current facilities are insufficient for reactivity mechanism training. In the event that the EPC contractor cannot use the existing DNGS training facility, a new facility wou															
			Outage Window		**Window Description**												
			000		000 – No Window Related												
12022	Possible Electrical Cable Insulation Damage When Replacing Flux Detectors [Window 28, 73]	Possible deterioration of existing cable insulation (from the Flux Detector to the Amplifier) when replacing Flux Detectors because aged cable insulation may be very fragile and breakdown upon contact.	3	Active	John Stopar	George Naguib	21-Oct-16	Mitigate	30-Nov-16	3	1	2	6	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8808	In Progress	Order VFD/HFD Spare Pigtails (JP1, JP2 and JP3)	This action is on the BOP Project to order spare pigtails for the ICFD replacement project. UPDATE 03FEB2017: HFD Pigtails will be replaced via EQ PM work. VFD spares exist in stores and an MR will be placed for approximately 10% spare of each type (J1,J2, and J3).	John Stopar	George Naguib	29-Mar-17								
			Outage Window		**Window Description**												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
14402	RM Drive Mechanism Damage due to handling and AA Replacement work [window #21 and #28]	This risk is associated with the possible damage to RM Drive Mechanisms during handling (ie. removal and reinstall of AA Drive Mechanisms) as well as surrounding work during AA rod replacement and VFD replacement work.		Active	John Stopar	George Naguib	13-Feb-17	Mitigate	20-Dec-16	3	1	2	6	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.						
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			028		028 - Replace Vertical Flux Detector												
14404	Risk of First Time Full Scale Horizontal Flux Detector Program [window #73]	Although ICFD's have been maintained at DNGS, they have not been replaced on a large scale addressing productivity issues, personnel (dose) and coordination with other work groups and projects.		Active	John Stopar	George Naguib	21-Oct-16	Mitigate	20-Dec-16	3	1	2	6	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.						
			Outage Window		**Window Description**												
			073		073 - HFD Replacements												
14717	Vendor Project Staff Retention	[redacted]		Active	John Stopar	George Naguib	13-Feb-17	Monitor	30-Jan-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
			128		128 - ECI Vault Work												
			129		129 - Temp Fission Chamber Install												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14717	Vendor Project Staff Retention	[redacted]	155		155 - Adjuster Mechanism Re-Install												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13635	Tooling and Design rework [Window 28, 73]	The risk is that due to complications with storing the In-Core Flux Detectors in the Irradiated Fuel Bay, rework on design may be required to revise the tooling. Should this occur, the impact will be to perform design that is above and beyond the current understood scope.	1	Active	John Stopar	George Naguib	21-Oct-16	Monitor	30-Nov-16	2	2	2	4	2	2	2	4
			Outage Window		**Window Description**												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14025	ICFD Lemo Connector Corrosion [Window 28]	OPEX from previous DNGS ICFD work indicates that there may be heavy corrosion on the U2 ICFD assembly heads, and more specifically on the lemo connectors. This risk is identified for contingency planning in case lemo connectors need be replaced. In more sever corrosion cases, single well may need to be abandoned if detectors cannot be installed. 10 Aug 2016 (J.Stopar): After closer examination of OPEX, the corrosion affecting new detector installation can be dealt with by simple cleaning at the top rim of the well. Spare wiring harnesses JP1, JP2 and JP3 are being ordered in order to have Lemo harness replacements should they be required.		Active	John Stopar	George Naguib	21-Oct-16	Mitigate	30-Nov-16	4	1	1	4	4	1	1	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8808	In Progress	Order VFD/HFD Spare Pigtails (JP1, JP2 and JP3)	This action is on the BOP Project to order spare pigtails for the ICFD replacement project. UPDATE 03FEB2017: HFD Pigtails will be replaced via EQ PM work. VFD spares exist in stores and an MR will be placed for approximately 10% spare of each type (J1,J2, and J3).	John Stopar	George Naguib	29-Mar-17								
			Outage Window		**Window Description**												
			028		028 - Replace Vertical Flux Detector												
14205	HFD Installation Challenges due to sagged guide tube [Window 73]	There is OPEX which indicates that installation of longer Horizontal detectors, with a dry moderator, may be presented by major challenges due to sagging of horizontal ICFD guide tubes. A response to this challenge may include delaying longer detector installations until after moderator fill. OPEX indicates the possibility that guide tube sag is less apparent with a full moderator. This would have possible impacts to the overall outage schedule if detector installs are pushed out.		Active	John Stopar	George Naguib	21-Oct-16	Accept	30-Nov-16	2	1	2	4	2	1	1	2
			Outage Window		**Window Description**												
			073		073 - HFD Replacements												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14207	Risk of Stuck Detector during HFD Program [Window 73] and VFD Program [Window 28]	There is a risk that, during horizontal in-core flux detector removals, a detector is lodged in the cutting chamber of the Stern ICFD Cutter Tool. Although the tool is built with contingency tooling for a number of "expected" stuck detector positions, contingency planning is required for a variety of other conditions. Due to the already high doses in the SDS2 bunker as well as significat dose rates coming off a stuck detector, contingency planning will need to involve minimizing the amount of time personnel are in the vicinity of the tool, as well as a well docunted process for safe stating the area in the case of stuck detector challenges. 10 Aug 16 (J.Stopar): Less extensive challenges exist for contingency planning associated with the VFDs . A solid plan needs to be formulated for VFDs also.		Active	John Stopar	George Naguib	21-Oct-16	Mitigate	30-Nov-16	2	1	2	4	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6756	In Progress	Contingency Plans for HFD and VFD Replacement	This action is associated with Risk ID 14207. Contingency planning for stuck detectors during the HFD and VFD replacement windows will need to be established prior to executing the work.	John Stopar	George Naguib	31-May-17	8 Aug 2016 (J.Stopar): Two contingency planning sessions have been conducted with the ICFD Tooling supplier and experienced end users who have performed work with the tooling at Darlington, Bruce, Pt Lepreau, Wolsong and Quinshan. Workable contingency plans have been formulated and the details to achieve them are being worked on. 21 Oct 2016 (G. Naguib): OPG and vendors are working on a new strategy to cut HFDs with the chopper tool off the HFD assemblies in order to create ease of execution and contingency planning. The design efforts by Stern to complete this new strategy will begin November 2016.				

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
14207	Risk of Stuck Detector during HFD Program [Window 73] and VFD Program [Window 28]	There is a risk that, during horizontal in-core flux detector removals, a detector is lodged in the cutting chamber of the Stern ICFD Cutter Tool. Although the tool is built with contingency tooling for a number of "expected" stuck detector															
			Outage Window		**Window Description**												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
14405	Risk of New flux detectors installed in incorrect location [window #28 and #73]	This risk is associated with the possibility of installing new flux detectors in the wrong location. Detectors are similar in fit and can be easily misidentified. This applies to both vertical and horizontal flux detector programs.		Active	John Stopar	George Naguib	14-Nov-16	Mitigate	15-Mar-17	2	1	2	4	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.							
			Outage Window		**Window Description**												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
12219	Horizontal Flux Detector Guide Tube Replacement [Window 73]	The risk is that the horizontal flux detector (HFD) guide tubes will need to be replaced. A calandria tube to HFD gap measurement is currently being completed by IMS to determine if there is a need to replace the HFD guide tubes. HFDs are prone to sag as calandria tubes are, which may result in contact between calandria tubes and HFDs during normal operation (sag until contact) or during refurbishment by removal or installation of calandria tubes.	3	Active	John Stopar	George Naguib	14-Nov-16	Accept	14-Dec-16	1	3	3	3	1	3	3	3
			Outage Window		**Window Description**												
			073		073 - HFD Replacements												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14582	Assessed Hours Greater than Project Estimate Hours [no window]	This risk is associated with the current assessed hours being greater than the project's estimate hours, resulting in increased construction costs.		Active	John Stopar	George Naguib	14-Nov-16	Monitor	31-Jan-17	3	1	1	3	3	1	1	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73514																	
13321	LPSW Alternative Cooling (Project # 73514) Interfaces with the BDBE and the BA Project components not ready [Window 57A, 57B]	The risk is that LPSW Alternative Cooling will not be available when required (MEC 124457) as a result of interfacing components (BDBE and the BA Projects) potentially not installed in a timely manner. The impact of this will be an inability to provide cooling water to the loads under MEC 124457, which may impact other project schedules.	3	Active	Scott Guthrie	Greg Mills	23-Jan-17	Monitor	17-Feb-17	2	2	3	6	2	2	3	6
			Outage Window		**Window Description**												
			057		057 - LPSW Outage Phase 2 & 3												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15120	LPSW Alternative Cooling (Project # 73514) Risk of EC Revisions leading to increased Costs [Window 057]	Design was completed on LPSW TMODs EC (MEC 124457) in early 2015. Despite this there is the continuing risk of costs associated with EC Revision to the project. Several issues have recently come to light which threaten to contribute considerably to Engineering support costs despite the fact that design is complete. An error discovered in DSP submitted and accepted CALC (no SCR). Errors discovered in legacy routing of fixed pipe and hose along TMOD pipe route. This has triggered a supplemental COMS (this may represent a COMS failure, no SCR). Errors in routing discovered as a result of recent walk downs where material changes to the plant have interfered with the proposed route requiring route revision. Improvements in routing suggested by vendor based on construction personnel review. Alternative pipe supports, improved routing, etc. This also could be considered a potential COMS miss.		Active	Marcus Sztrimbely	Greg Mills	24-Jan-17	Mitigate	01-Sep-17	4	1	1	4	1	1	1	1
			Outage Window		**Window Description**												
			057		057 - LPSW Outage												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Balance of Plant - 73550																	
14401	AA & ICFD Replacement Staff Experience [window #21]	This risk is associated with the introduction of new tooling and processes to staff with little experience in performing the work. AA Rod Replacement has never been performed at Darlington and is new to the contractor. Horizontal ICFD is also a FIAW activity that is being performed by a vendor that has never performed the work before. In addition, discharge of flux detectors into the IFB is new to DNGS. The lack of experience is associated with the tooling/work process of replacing/discharging AA rods, assembly/installation of correct AA Rod Types and horizontal flux detector removal/install and discharge into the IFB.		Active	John Stopar	George Naguib	13-Feb-17	Mitigate	31-Oct-16	4	4	4	16	2	2	1	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.		John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.						
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
15056	AA Rod Removal and Discharge Tooling [window 21]	Event: AA rod removal and discharge tooling may not be ready/available in time for window start Cause: Impact: Background: This risk is associated with the readiness/availability of AA rod removal and discharge tooling in time for window start.	4	Active	John Stopar	George Naguib	05-Dec-16	Monitor	01-Feb-17	4	2	2	8	4	2	2	8
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12418	Adjuster Rod Replacement Construction Costs [Window 21]	Due to the large delta between third party and EPC Vendor estimates for Construction costs, associated with Adjuster Rod removal, installation, and holding rack modification, there is a risk that the estimated construction costs at Gate 2H are increased in Phase 2 of the project.	3	Active	John Stopar	George Naguib	13-Feb-17	Monitor	15-Oct-16	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13578	The Risk is that items to be procured by the Balance of Plant Project may have lead times greater than expected [Window 021]	Event: The items to be procured by the Balance of Plant Project may have lead times greater than expected Cause: Impact: This would impact the execution schedule. Background: In general, a valid mitigation strategy will be to expedite shipments through the procurement vendors.	3	Active	Scott Guthrie	George Naguib	13-Feb-17	Monitor	31-Dec-16	2	2	3	6	2	2	3	6
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13902	Seismic Requirements for Flask Use on RMD [Window 21]	There is a risk that further engineering and work planning effort will be required to address the seismic requirements for use of the RM flask over the RMD. Due to the seismic requirements on the RMD, an assessment to confirm no seismic risk is imposed on reactor mechanisms and associated equipment, as a result of AA rod removals from the reactor core.		Active	John Stopar	George Naguib	14-Nov-16	Monitor	19-Dec-16	3	2	2	6	3	2	2	6
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14402	RM Drive Mechanism Damage due to handling and AA Replacement work [window #21 and #28]	This risk is associated with the possible damage to RM Drive Mechanisms during handling (ie. removal and reinstall of AA Drive Mechanisms) as well as surrounding work during AA rod replacement and VFD replacement work.		Active	John Stopar	George Naguib	13-Feb-17	Mitigate	20-Dec-16	3	1	2	6	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.		John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.						
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			028		028 - Replace Vertical Flux Detector												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14717	Vendor Project Staff Retention	[redacted]		Active	John Stopar	George Naguib	13-Feb-17	Monitor	30-Jan-17	3	1	2	6	3	1	2	6

Outage Window	Window Description
021	021 - Replace Adjuster Rods
028	028 - Replace Vertical Flux Detector
073	073 - HFD Replacements
128	128 - ECI Vault Work
129	129 - Temp Fission Chamber Install
155	155 - Adjuster Mechanism Re-Install

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15057	At Risk Procurement of Adjuster Rods [window 21]	Event: Adjuster rods may not be delivered in time for window 21 (March 2017) Cause: Due to fabrication issues, and concerns regarding the straightness spec of the adjuster rod outer tubes, and requirements for stress relief post straightening Impact: Background: Due to fabrication issues and concerns, the supply of adjuster rods for window 21 (March 2017) is currently at risk. There are concerns regarding to the straightness spec of the adjuster rod outer tubes and any requirements for stress relief post straightening. Due to these concerns, the manufacturing of outer tubes is on hold, and therefore placing the delivery of rods at risk.		Active	John Stopar	George Naguib	13-Feb-17	Monitor	01-Feb-17	3	2	2	6	3	2	2	6

Outage Window	Window Description
021	021 - Replace Adjuster Rods

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14393	ALARA Risks Associated with AA Replacement Project [window 021]	Due to the nature of the AA Replacement work, there is a potential for contamination spread and a risk of unplanned exposure during the removal process.		Active	John Stopar	George Naguib	13-Feb-17	Mitigate	30-Jun-16	2	1	2	4	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.

Outage Window	Window Description
021	021 - Replace Adjuster Rods

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14399	Integration Risk between AA Replacement and other work groups [window 021]	There is a risk that other work groups will be affected by the AA Rod Replacement project execution (ie. flask maneuvering/transport, access control due to radiation, etc.).		Active	John Stopar	George Naguib	13-Feb-17	Monitor	30-Jun-16	2	1	2	4	2	1	2	4

Outage Window	Window Description
021	021 - Replace Adjuster Rods

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14400	Adjuster Rod Toolset [window #21]	The existing Adjuster Rod replacement toolset at Darlington is not complete.		Active	John Stopar	George Naguib	10-Aug-16	Monitor	30-Sep-16	2	2	1	4	2	2	1	4

Outage Window	Window Description
021	021 - Replace Adjuster Rods

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14208	Adjuster Absorber Rod Drop During Replacement [Window 21]	This risk is associated with the risk of dropping an adjuster absorber rod in one or both of the following scenarios: 1. Upon removal of spent AA Rods with the RM Flask. 2. Upon Installation of new AA rods into the reactor core. The impact of a dropped rod may result in severe damage to the AA rod itself as well as possible guide tube and locator damage.		Active	John Stopar	George Naguib	10-Aug-16	Mitigate	30-Sep-16	1	2	3	3	1	2	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

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14208	Adjuster Absorber Rod Drop During Replacement [Window 21]	This risk is associated with the risk of dropping an adjuster absorber rod in one or both of the following scenarios: 1. Upon removal of spent AA Rods with the RM Flask. 2. Upon Installation of new AA rods into the reactor core. The impact of a dropped rod may result in severe damage to the AA rod itself as well as possible guide tube and locator damage.	7886	In Progress	BoP AA/ICFD Mockup and Wet Casket Bay/IFB Training Completion	AA rod removal/wet casket bay training and ICFD/IFB training is required to be implemented in two separate events 1) with a smaller management/supervisory team to validate the procedures, durations and equipment 2) Immediately prior to field work with trades staff/supervision to ensure familiarity with all applicable procedures/tooling. 3) Resource bridging strategy so that a subset of the AA trades are maintained for use in the ICFD window.	John Stopar	George Naguib	15-Mar-17	10 Aug 2016 (J.Stopar): Training for Adjuster and ICFD replacement includes practical evaluation of worker proficiency and knowledge. A high hazard rehearsal is also included at the end of the training program. Training will emphasize the fact that the maintenance activities are taking place in midst of sensitive equipment.							
			Outage Window	**Window Description**													
			021	021 - Replace Adjuster Rods													
14209	Less than Adequate AA Guide Tube Gap Inspection Results [Window 21]	This risk is associated with the risk that the AA vertical guide tube gap inspection on AA13 guide tube at the back end of the AA replacement program results in less than adequate measurements. Although the OPEX indicates that the risk is low, there would need to be extra work planning and execution work required to fix the gap measurements and study the extent of condition.		Active	John Stopar	George Naguib	10-Aug-16	Accept	30-May-17	1	3	3	3	1	3	3	3
			Outage Window	**Window Description**													
			021	021 - Replace Adjuster Rods													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14403	RMD Mockup for AA Replacement [window #21]	Risk is that the RMD Mockup does not adequately reflect the field interferences from surrounding mechanisms, due to the complexity of interferences in the reactivity mechanism deck. This will impact on construction efforts in the field.		Active	John Stopar	George Naguib	23-Sep-16	Mitigate	31-Oct-16	3	1	1	3	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8835	In Progress	Adjusters - Construct and Apply Go-No Go Gauge for Confirmation of Removal equipment Fit-up on the RM Deck	Risk mitigation will be achieved by constructing a go-no go gauge and using it on the Unit RM Deck at all 16 replacement sites in order to ensure that the removal tooling with fit in amongst the interferences. This exercise will occur late in 2016 after unit 2 is shut down.	John Stopar	George Naguib	15-Mar-17								
			Outage Window	**Window Description**													
			021	021 - Replace Adjuster Rods													

Project: Balance of Plant - 73572

15130	Risk of compromising the ASDC project due to rebar cutting in rooms R2-015 and R2-065	Due to the concrete slab thickness, drilling the holes for anchoring the ASDC pumps on the ceiling in room R2-015, may result in cutting more rebar than the value established as acceptance criteria by the design analysis. If this occurs, then other design options shall be explored, leading to significant cost ($1.5M) and schedule impact		Active	Katie Stewart	Doina Idita	03-Mar-17	Accept	30-Nov-17	4	2	5	20	4	2	5	20
			Outage Window	**Window Description**													
			124	124 - SDC Rm Work													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15129	Additional design changes due to supports requirements	Due to the increase of the KSB nozzle loads, some of the piping supports using the nelson studs (located on the containment liner) may not pass the supports stress analysis acceptance criteria. New Supports Imposing Combination Loads on Nelson Studs Beyond OPG Standards are required to be checked with the manufacturer. Manufacturer design/safety range/ margins to be used within stress analysis. If this risk occurs then project cost and schedule will be impacted.		Active	Katie Stewart	Doina Idita	03-Mar-17	Accept	26-Jan-17	4	1	4	16	4	1	4	16
			Outage Window	**Window Description**													
			124	124 - SDC Rm Work													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15126	Design cost increase du to the changes on the ASDC pressure and flow switches	There is a code requirement for remote RV indication for Class 2 pressure piping. The proposed solution was to provide a PS and FS upstream and downstream of the RV, respectively. There is a risk of design change if the vendors confirmation is not received for the required/specified materials to be used during manufacturing. If the PS/FS available on the market does not conform to the requirements of the Design Specifications, then a design change is required on two I&C DECs 128656 and 128658		Active	Katie Stewart	Doina Idita	26-Jan-17	Monitor	15-Mar-17	3	1	4	12	3	1	4	12
			Outage Window	**Window Description**													
			124	124 - SDC Rm Work													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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15127	Design cost increase due to balance of the vendor documentation	Vendor Documentation: All required vendor documentation to progress ECs have been advanced through design completion (with granted deviations by the DA at the DCAVR). However, the balance of documents that are expected from the vendor (i.e. manuals, test reports, etc.) pose a risk on the design. There are several KSB and Velan design documents currently outstanding. Most are at advanced stages of C&D but still carry some residual risk of changing. Due to the issues confronting the anchor DEC, there is a risk that KSB mounting plate may be affected. A design change maybe required if KSB plate has been changed.		Active	Katie Stewart	Doina Idita	26-Jan-17	Monitor	01-Sep-17	2	1	4	8	2	1	4	8
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15134	Possible design cost increase due to the pipe whip analysis	There is a risk of design cost increase due to : -The review of the ITF or AVL documents may re-open certain closed items.A majority of the items were reviewed and closed out as part of submission of R0 of the DEC. However, different reviewers at this time may hold a different view.-Pipe whip for R-065 to support floor loading assessment for anchor DEC.Currently the scope for pipe whip analysis to support safety case is unclear. If a non-linear analysis is required, then several hundred hours of effort will be needed. -Final nozzle loads will not adversely impact the floor loading assessment or anchor calculations for pump installation (DEC 137042). To meet design completion schedule for DEC 137042 work progressed at risk without finalized piping loads (as the DEC 128660 was being revised). The nozzle loads are nearly final with nearly final vendor information. The revised nozzle loads will be incorporated in the 100% design submission.- Confirmatory walk-down for DEC 128660 may reveal information that may require further design iteration. With the design being finalized, a confirmatory walk-down is required to ensure there are no further issues in the field. As such, there remains a risk that some information will be revealed triggering changes to the design. The confirmatory walk-down may reveal some interferences with existing design, with a higher risk on support designs. While this may be a cost in the front-end, it will save significant issues during construction. The Aux SDC pumps has utilized 3D laser scans and team members have completed numerous walk-downs to obtain field info		Active	Katie Stewart	Doina Idita	26-Jan-17	Monitor	30-May-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15202	ASDC - Design cost increase	There is a risk of ASDC design cost increase due to the following:- stakeholders concern with respect to the impact of heat transfer from the ASDC pump to the concrete from: (a) tack welds on the top-plate; and (b) the pump mounting plate temperature due to the medium. Note: This item has been included in the ITF and if a qualitative disposition is not acceptable, then funding will be required to complete a more detailed heat transfer calculation + concrete assessment.- There is an unresolved comment on the floor loading assessment report from OPG Civil design, which required additional plate vs. shell sensitivity analysis for the concentrated loads. Additional effort may be required to address this unresolved comment.- A deviation from L-964 spec is required to proceed with core drilling and potential rebar cutting for the floor slab in R-065. If the deviation memo is not accepted, then a significant re-design maybe required.- Required clearance for grouting between the through bolt and the concrete hole walls is too large. There maybe a need to cut two adjacent rebars while drilling holes for the through bolts. additional analysis may be required to nail down the acceptance criteria for rebars cutting.		Active	Katie Stewart	Doina Idita	27-Feb-17	Monitor	30-Nov-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			040		040 - Class 2 Electrical Rehab												
			104		104 - Vault Projects Before Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14669	Revision of the Mechanical Design EC 128660 [window 124]	The final stress analysis of the Auxiliary Shutdown Cooling modification is going to be performed hand in hand with the revision 01 of the DEC 128660. The final stress analysis is mainly required for the final TSSA registration of the ASDC modification. There is a risk of performing a new revision (Rev.02) of the mechanical DEC128660 based on the results of the final stress analysis.		Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	15-Sep-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73592																	
13369	73592 - Vault Work Interferences with JV Work [Window 8]	BoP project work will get delayed due to JV work being on critical path, this will lead to a contractor stand down resulting in additional costs and schedule delays. This will affect the vault work for the containment projects, e.g. Installation of the manifolds, roll-up doors at the airlocks and transfer chamber doors. Per FOAK feedback, actions associated with this risk will be allocated against the applicable BoP projects that are at risk such as NPC, EHS, ASDC & the cross cutting area of radiography/PAUT.		Active	Katie Stewart	Amanjot Singh	02-Feb-17	Monitor	30-Mar-17	3	2	3	9	3	1	3	9
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

13369	73592 - Vault Work Interferences with JV Work [Window 8]	BoP project work will get delayed due to JV work being on critical path, this will lead to a contractor stand down resulting in additional costs and schedule delays. This will affect the vault work for the containment projects, e.g. Installation of the manifolds, roll-up doors at the airlocks and transfer chamber doors. Per FOAK feedback, actions associated with this risk will be allocated against the applicable BoP projects that are at risk such as NPC, EHS, ASDC & the cross cutting area of radiography/PAUT.	3436	In Progress	Alternate NDE Required: Radiography Cannot be Performed inside the Vault	Currently identified ~82 piping welds inside the vault (excluding feeders). the balance of plant and P&M scope is listed below. The action is to develop a path forward for an alternative to conventional radiography and implement these alternatives. Note: Action due date is tied to completion of first occurrence of alternate RT methods. Project # Project Name Applicable Window Start of Welding NDE Locations 73202 NR TS0100-2: ECT INSPECT BLEED COOLER 2-33320-HX2 (Cont'g ONLY) 105 Sept 2017 2 73648 NR DSR SI0050-1 EMERGENCY HEAT SINK MECH 2-33410-L124 105 May 2017 22 73380 DR SIO Shield Tank Over Press Protection (STOP) 105 1-Aug-18 5 73763 REPLACE 2-33330-PV1 VALVE BODY 105 7-Sep-17 2 38349 Spectacle Flange Replacements TBD August, 2017 10 38933 DN PHT LRV Modifications (Waterhammer) 31 June, 2017 35 73407 Check Valve Replacements (NV23, 24, 61, 36) 105	Scott Guthrie	Kristopher Probodiak	31-May-17	March 1, 2017 Small Controlled Area Radiography and Pulsed X-Ray are currently available options and alternatives to conventional radiography. Actions are in place to enable projects. Safety, Quality, Schedule, etc. are being addressed and reported on regularly at the project issues meeting. Funding has been made available to have IMS support the initiative and provide QA oversight, RP planning, etc. Refer to issue 294 for regular updates. first occurrence of SCAR is expected in May 2017 pending any project schedule changes. ***OLD Status Updates prior to Feb 2017***** all work groups/ projects to id their vault radiography requirements to Dennis. Boyd - requested to determine other if other "non-radiography" technologies avail. Jan 15th, 2015: Did discuss this with vendors (ES Fox and AMEC) and we have a path forward to determine radiography amounts (still unknown as piping modelling is underway), I'll get you detailed drawings when the modelling is done. 4Feb2015 note: all in vault projects to strive to not have to radiograph. As JV is working 6x10h: Sunday will be "radiography day". 28Apr2015 note: unkown currently how much radiography is required...this will be known better as design progresses. Due date pushed to EHS 40% design complete date for follow up. Vendor looking into other forms of NDE for pipe welds. 4-Sept-2015 Update: Will confirm amount of NDE through assessing/work planning phase. 3-Feb-2016: it was recently raised in the vault window meeting that radiography may not be allowed. This will affect multiple projects in the vault project window that require radiography. Other means of NDE is being investigated. 5-Apr-2016: This action is going to be canceled once a new action is generated and linked to a Program Risk, instead of Project Risk. The new action will be noted before this action is closed. Updates: Contacted IMS to investigate Phased Array option as an alternative. IMS to deliver proposal to BOP. 22 June 2016 (J.Stopar): This Proj

						20-Feb-18 4 73750 Valve PMs - 2-32110-NV37 TBD 17-Jul-18 2																
			5242	In Progress	BoP NPC Project - Vault Work Interferences with JV Work.	The risk response is to monitor and mitigate as possible. Regular meetings are set-up with the Work Control group and JV to determine vault interfaces (iSEP and Vault Coordination meetings) to determine optimal work windows for all groups and potential impacts that may arise. For the containment project, the installation of the manifold and the airlock/transfer chamber roll up door required vault access. 6 workers at $6000 per week for 2 weeks 6 workers at 16 hours a day for 2 weeks (10 days) = $96K	Ajay Upadhyaya	Katie Stewart	31-Jul-17	24 Nov 2016 up-date: On going meetings between project, OPG SWIC and JV are schedule, All potential interferences are reviewed and mitigating actions identified and assigned. This is an op going process. 26 Jan 2016 up-date: No interference is identified at this time.									
			Outage Window		**Window Description**																	
			008		008 - RFR Prereq prior to Containment Isolation																	
Project: Balance of Plant - 73613																						
14291	Stopple Plug: Risk of burn through during welding of split tee (PMOD) [Window 57]	During the workplan review for the stopple plug modification, it was identified that there is a risk of burn through of the 20" pipe during welding of split tee. This poses a potential for an unisolable leak from the Inter Unit Service Water Header (IUSWH). The maximum size of the leak would depend on the extent of any breach. Large leaks, while having a very low probability of occurrence, would have potentially severe consequences including flooding of U2 (north of Column Line 11 thus potential effects on U0 and U1) as well as the potential to impact on the operation of LPSW systems of Units 1, 3, and 4. Both of these events, should the break size be sufficiently large, would introduce a severe transient situation to the Plant and would likely require the use of a Group 2 Heat Sink in order to maintain Nuclear Safety. The risk of these events has been mitigated by the following considerations: - Welding, hot tapping, and stopple plugs have extensive OPEX behind them showing that with careful planning and adherence to industry best practice, failure scenarios are either extremely remote or unheard of.- Inspections of the piping for wall thickness and inner surface conditions will verify that conditions to perform the operations are satisfactory, UT scans have been performed already and show that the wall thickness within the welding requirements. UT scans and confirmation of thickness are to be performed as pre-req's to welding activities.	1	Active	Katie Stewart	Amanjot Singh	02-Feb-17	Monitor	03-Apr-17	1	2	3	3	1	2	3	3		
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**												
			7189	In Progress	Window 057 - Stopple Plug - Determine The Need For Additional Tasks For Safe Work Area / Extenting Safe Work Area	Off site schedule review Apr.19,2016	Amanjot Singh	Amanjot Singh	31-Mar-17	Per WO 3228917, the following task is related to safe work area: 11 - BCR ERECT PROTECTIVE BARRIERS PRIOR TO HOT TAP Further details are required to be input to align with WPL, eg. water spill/splash precautions such as spill kits, staging of catch containment and FME barriers. Tarps will be set up to protect nearby electrical equipment.									
			Outage Window		**Window Description**																	
			057		057 - LPSW Outage Phase 2 & 3																	
15144	Stopple Plug: TD Willaimson Equipment changed from original.	Event: SUPPORTS DESIGNED FOR ORIGINAL EQUIMENT MIGHT NEED TO BE CHANGED. Cause: Due to change in design from TD Williamson equipment Impact: cost and schedule impact Background: TD Williamson equipment on the basis of which RCM(Design agency) designed the supports has been changed. RCM insists design for the supports needs to be done again in order to accommodate the latest equipment. This will result in added financial cost and schedule impact incase the equipment arriving on site is different.	3	Active	Marcus Sztrimbely	Amanjot Singh	01-Mar-17	Avoid	10-Aug-17	1	1	3	3	1	1	1	1		
			Outage Window		**Window Description**																	
			000		000 – No Window Related																	
			There are no Draft, Not Started, In Progress Actions associated with the risk.																			
Project: Balance of Plant - 73618																						
14609	Risk of NICR or full Modification required for failed UST relay [window #004]	A new relay may be required which will require a NICR or a full modification. Identified at Deer Creek meetings as a result of a work request found in the system. Relay has been performing in a manner which suggests failure is imminent. Work order in question is WO 04869979-01 ("NR REPLACE 2-52120-T2-3-R3 DURING REFURB"). Note: WO 04869979 has now been cancelled, see WO 3259913. Note, this WO is not yet BOP scope. BOP Director will not accept this as project scope until material issue resolved.		Active	Koon Han	Greg Mills	05-Jan-17	Monitor	15-Dec-16	2	2	2	4	2	2	2	4		
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The following sub-actions are indicated:
1) AREVA and Refurbishment Engineering to review and advise on whether part is likely to be available. - COMPLETE, part is not commercially available, however a digital version of this item is available. Popular opinion is that this is beyond a NICR, and would be a full modification.
2) Refurbishment assessing to review and place hold as required. - COMPLETE, WO 3259913 (originally 4869979) ENA hold placed August 8.
3) Refurbishment Design to review, prioritize and produce design product required. - CANCEL, no traction
4) Contact work control and resolve that scope either gets assigned to the EPC vendor, or is removed from refurb. COMPLETE: John Culligan is prioritizing requests into the screening committee.
5) Arrange for AREVA troubleshooting with support of the system engineer. This will require bringing the troubleshooting tasks into scope, MCD, CCF, etc. TCD: CANCEL, project change estimate was presented to BOP director mid-Feb 2017. Rejected as not BOP scope.
6) Request MCD for troubleshooting from AREVA. COMPLETE: MCD received (not accepted by BOP director. $ 25 k)
7) As vendor execution has been ruled out by BOP Director, pursue Maintenance support for troubleshooting: COMPLETE, Brad Schofield has agreed to perform troubleshooting, scheduled for March 6, 2017 (WO 3259913-02)
8) Review results with System Engineer: Yet TO START, TCD: March 30, 2017
9) Initiate required actions to support U2 return to service based on item 8) above. YET TO START, TCD: April 17, 2017

Outage Window	Window Description
004	004 - MOT/UST/IPB Rehab

Project: Balance of Plant - 73628

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15181	73628 Emergency Lighting-Risk of New EP Creation	Event: Electrical cable may not fit in the existing EP's, requiring additional tooling and labour for EP drilling to create a new EP for the cable. Cause: The size of Teck cable that is be run through EP 41218 and the amount of space left in the EP to fit another cable Impact: Additional costs for tooling/labour, Schedule delays to obtain appropriate approvals and execute work Background: Teck cable is to be run through EP 41218, however, the penetration is fairly full and may not be able to accommodate the size of the cable. ITF Item 43 was created to poke a hole through the EP to determine whether the cable can fit. There is risk that the cable may not fit through the EP or that other cables may be hit when removing the sealant to accommodate the new cable. EP 41217 may also be used but it is also fairly full. If the cable can not fit in the existing EP, there is a risk that drilling will need to occur through the concrete wall to create a new EP for the cable. If drilling through the concrete wall is to occur, this can impose a cost and schedule impact to the project and will also trigger the update of multiple engineering drawings to document station configuration.	3	Active	Marcus Sztrimbely	Breanne Stramenga	01-Mar-17	Monitor	12-Jun-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13352	[Window 515] Risk of detector accessibility	The Risk is that detectors in the field are not accessible for replacement. Should this be the case, relocation is the only option for the modification. This will be addressed via a FIC, and required more time and effort than anticipated, as the FHA/FSSA must always be adhered to. Any relocations must be reviewed, validated, and approved by the Design Services Provider as the design basis must be protected.	3	Active	Oweis Chohan	Jacob Davis	21-Nov-16	Monitor	30-Apr-17	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			515		515 - U2 SCID 7083 Fire Alarm Upgrades												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15137	73628 Emergency Lighting-Potential Work Interferences with Fuel Handling Work	Event: The Emergency Lighting Modification may face delays during the construction window/installation Cause: Due to day to day Fuel Handling activities and other station/refurb work that is given priority. FH is the primary work group in the FH maintenance shop. Impact: Schedule delays. Background: The planned SOI is currently in April 2017,however, the SOI may move depending on the window in which FH will not interfere with project work. As well, there is risk that delays may be encountered during installation as construction crews may need to stand down to allow FH to proceed with their work. Night shift work may result to avoid work group interferences.	3	Active	Marcus Sztrimbely	Breanne Stramenga	01-Mar-17	Monitor	20-Apr-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14509	[Window 515, 516] Resources for Fire Alarm and Fault Isolator installation and Commissioning	There is a significant threat to the installation and commissioning of the fire alarms and fault isolators project. The issue is that the work plan is calling for (2) full time control techs to support the work throughout the project.		Active	Brad Schofield	Jacob Davis	21-Nov-16	Monitor	03-Apr-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			515		515 - U2 SCID 7083 Fire Alarm Upgrades												
			516		516 - U2 SCID 7085 Fire Fault Isolators/U2 SCID 7084 SST Containment/U0 SCID 7081 Change Room Mods												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15138	73628 Emergency Lighting-Foil Insulation Interference	Event: Cable fasteners procured for this project may not accommodate the material under the foil insulation, and require Additional DBOM items to be ordered Cause: Due to unknown material (not indicated on plant configuration drawings), NR Design cannot determine type of cable anchorage required (ie. for steel or concrete) Impact: cost impact Background: Foil insulation located on the ceiling of S-141 will need to be removed as an interference in order to run cables along the ceiling. Since the plant configuration drawings do not indicate the type of material under the foil insulation, NR Design can not determine the type of cable anchorage required (i.e. for steel or concrete). Construction delays may occur if the cable fasteners procured for this project can not accommodate the material underneath the foil insulation. As well, if sufficient cable slack is discovered under the foil insulation the design may need to be modified in order to reduce the number of junction boxes required.	3	Active	Marcus Sztrimbely	Breanne Stramenga	01-Mar-17	Monitor	01-May-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Balance of Plant - 73639																	
13260	PHT & Aux - Heat Exchangers Require Replacement [window 048]	The risk is that the D2O Collection Tank and Vent Condenser heat exchanger tubes will have degraded to a point which requires heat exchanger tube bundle replacement. This is part of the PHT & Aux rehabilitation project.	1	Active	Scott Guthrie	Hassan Baharvandy	07-Mar-17	Accept	30-Jul-17	2	1	2	4	2	1	1	2
			Outage Window		**Window Description**												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73648																	
13314	EHS Vault Work Interferences with JV Work [Window 68, 104, 105]	Event: Emergency Heat Sink contractors may have to stand down during planned work windows to allow for JV critical path work to be completed Cause: Impact: Cost and schedule delays Background: The risk is that the Emergency Heat Sink project will face schedule delays during planned work windows due to interferences with the R&FR/JV work. The EHS project will get delayed due to JV work being on critical path for a variety of reasons (eg: high radiation beams in vault, work interferences in similar areas of the vault, etc.) which will lead to a contractor stand down resulting in additional costs and schedule delays.	1	Active	Katie Stewart	Hassan Baharvandy	07-Mar-17	Monitor	15-May-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**												
			068		068 - Emergency Heat Sink												
			104		104 - Post Feeder Vault Projects												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73696																	
13644	Fission Chamber Guide Tube Redesign Risk [Window 129] (This Risk is REALIZED)	The Risk is that due to clearance issues caused by RF&R components or hot conditioning, there will be a requirement to redesign the fission chamber guide tubes.	1	Active	John Stopar	George Naguib	14-Nov-16	Monitor	16-Jan-17	3	2	2	6	3	2	2	6
			Outage Window		**Window Description**												
			129		129 - Temp Fission Chamber Install												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14717	Vendor Project Staff Retention	[redacted]		Active	John Stopar	George Naguib	13-Feb-17	Monitor	30-Jan-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			021		021 - Replace Adjuster Rods												
			028		028 - Replace Vertical Flux Detector												
			073		073 - HFD Replacements												
			128		128 - ECI Vault Work												
			129		129 - Temp Fission Chamber Install												
			155		155 - Adjuster Mechanism Re-Install												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12311	Fission Chamber Guide Tube Installation Risk [Window 129]	The risk is that possible misalignment between the view port, thimble and calandria nozzle will hinder installation of the temporary fission chamber guide tube.	2	Active	John Stopar	George Naguib	14-Nov-16	Mitigate	15-Aug-17	2	2	2	4	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8833	In Progress	Install Fission Chamber Guide Tube Well Before Intended Use	The fission chamber guide tube may experience mechanical interference or fit-up issues when being installed into the Viewport. The initial installation must occur well before the intended use of this component in order to allow recovery time. The guide tube complete with fission chambers must be functional prior to fuel load.	John Stopar	George Naguib	30-Sep-18								
			Outage Window		**Window Description**												
			129		129 - Temp Fission Chamber Install												

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14406	Risk that Detector does not meet Specification [window #129]	There is a risk associated with the performance of the selected fission detectors such that they will not provide the functionality required by the specification.		Active	John Stopar	George Naguib	14-Nov-16	Monitor	30-Jun-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			129		129 - Temp Fission Chamber Install												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13642	Schedule Delays for Fission Chambers [Window 129]	Due to the nature of the Fission Chamber work, there is some probability that issues during startup, reinsertion, and repositioning may affect startup. The result of this work would be increased time for labour hours above and beyond the estimated value	1	Active	John Stopar	George Naguib	14-Nov-16	Monitor	07-Aug-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			129		129 - Temp Fission Chamber Install												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73750																	
14992	Skilled Trades Availability from Union Hall	Event: Skilled trades may not be available from Union Hall during peak time. Cause: Shortage of skilled labor and parallel work going on. Effect: Cost, schedule and quality of work	3	Active	Anisha Bhasin	Anisha Bhasin	21-Nov-16	Monitor	20-Jan-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14413	DNRU2 Valve Project 73750 Phase 2 cost escalation (Windows 122, 124, 029, 057)	Event: Current estimate for the execution phase of the valve rehab project may increase substantially Cause: due to full assessing complete and current revision of the schedule differs greatly from the time contract initialization. Impact: Cost impact	3	Active	Marcus Sztrimbely	Anisha Bhasin	31-Jan-17	Mitigate	26-Oct-19	4	2	2	8	2	2	1	4
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			057		057 - LPSW Outage Phase 2 & 3												
			122		122 - Moderator Valve Rehab												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14574	Project 73750 - Window execution dates misaligned with Valve Delivery dates [No window related]	Event: Delivery of parts may be after the start of the window and may interfere with the critical path. Cause: All the POs to the sub-suppliers have not been placed yet and Window execution dates misaligned with the current Valve Delivery dates. Impact: schedule delays to critical path	3	Active	Marcus Sztrimbely	Anisha Bhasin	31-Jan-17	Monitor	30-Apr-17	2	2	4	8	2	2	4	8
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14370	Project 73750 Valve Rehabilitation - Risk of system modifications due to increased weight of replacement valves (Window 122)	Event: System mods may be required in order to accommodate the significantly higher weight of the new valves Cause: The installed valves are obsolete and not currently available like-for-like (new valves have significantly higher weights than the original valves) Impact: Cost and schedule impact background: The Valve Rehabilitation Project covers 80 valves - a subset are subject to replacement with new. A number of replacement valves are not available like for like with the original, and are being addressed with NICRs. During preparation of the NICRs as part of the procurement process, it became known that some replacement valves have significantly higher weights than the original valves.	3	Active	Scott Guthrie	Anisha Bhasin	31-Jan-17	Monitor	28-Feb-17	2	2	3	6	2	2	3	6
			Outage Window		**Window Description**												
			057		057 - LPSW Outage												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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Risk Report by Project with Associated Actions

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15195	Project 73750 - Actuators would not perform adequately when re-installed	Event - The actuators may not function adequately when re-installed, and require overhaul or replacement Cause - The actuators have not been overhauled since they were first installed and have only gone through MOVATs as PM work. Impact - delays to schedule and costs to expedite parts for overhaul or replacement. Background - The actuator overhauls have not been scoped as part of DNRU2 and there is a risk that the actuator will not function when re-installed. A detailed analysis by components engineering required a minimum of 12 actuators to be overhauled and the rest to be inspected for lube PM. However, the work requests to bring the actuator overhauls have been cancelled by SRE.	4	Active	Marcus Sztrimbely	Anisha Bhasin	24-Feb-17	Mitigate	31-Mar-17	2	3	3	6	2	3	3	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12295	Project 73750 - Insufficient Temporary Facilities To Support Valve Rehab Scope resulting in delays and cost increase [Window 29,57,122,124]	Event - Valves may need to be removed offsite (i.e.decontam / ship contaminated valves off site). This may affect the following windows: 29, 48, 54, 57, 103, 104, 122, 124, 131 Cause - Unforseen needs associated with valve rehab facilities cause Temporary facilities on site to be inadequate. Impact - Additional facilities required causing schedule and cost impact. Background: Much of the valve work will need to be performed "on-site" (due to contamination and logisitics of welded in valves)	3	Active	Marcus Sztrimbely	Anisha Bhasin	31-Jan-17	Monitor	30-Nov-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			029		029 - HTS Vac Dry												
			048		048 - HTS Aux Drain, DFead Legs and Purge,Outside Vault												
			054		054 - Instrument Air Maintenance												
			057		057 - LPSW Outage Phase 2 & 3												
			078		078 - Remove Mod Dry Equipment												
			103		103 - Establish Upper Calandria Purge Flow & E/W Valve Maintenance												
			104		104 - Vault Projects Before Feeder Removal												
			122		122 - Moderator Valve Rehab												
			124		124 - SDC Rm Work												
			131		131 - REMOVAL Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12305	Project 73750 - Risk of Increased Cost Due to Valve / Actuator Discovery Work or as a Result of Obsolete Valves [Window 29, 122, 124, 131]	Event - Actuators may not be adequate for new valves and may need to be replaced. During this work, there is the potential for 'discovery' issues to arise that will need to be addressed in order to return the valve to proper working order (either the valve or the actuator). May also result in NICRs being required. This may affect windows: 29, 48, 54, 57, 103, 104, 122, 124, 131 Cause - Inaccurate drawings leading to valve to actuator fit up problems. Valves will be replaced / repaired / overhauled as per the current approved scope. Impact - Depending on the severity of the issue there could be cost or schedule impacts.	3	Active	Marcus Sztrimbely	Anisha Bhasin	31-Jan-17	Monitor	31-Jul-17	1	2	2	2	1	2	2	2
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			048		048 - HTS Aux Drain, DFead Legs and Purge,Outside Vault												
			054		054 - Instrument Air Maintenance												
			057		057 - LPSW Outage												
			103		103 - Establish Upper Calandria Purge Flow & E/W Valve Maintenance												
			104		104 - Vault Projects Before Feeder Removal												
			122		122 - Moderator Valve Rehab												
			124		124 - SDC Rm Work												
			131		131 - REMOVAL Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13778	Project 73750 - Additonal Tenting for Contamination Control - Valve Rehabiliation [Window 29, 48, 54, 57]	Event - Implementation of tenting for contamination control may require a modification. Activities that may cause loose/airborne contamination include use of an arter grinder for valve overhaul. This may affect windows: 29, 48, 54, 57, 103, 104, 122, 124, 131 Cause - Procedures drive the requirement for a temporary modification. Impact - Cost impact due to additional resources needed for TMOD.	1	Active	Scott Guthrie	Anisha Bhasin	31-Jan-17	Monitor	31-Jul-17	1	1	2	2	1	2	1	2
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			054		054 - Instrument Air Maintenance												
			057		057 - LPSW Outage Phase 2 & 3												
			103		103 - Establish Upper Calandria Purge Flow & E/W Valve Maintenance												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13778	Project 73750 - Additonal Tenting for Contamination Control - Valve Rehabiliation [Window 29, 48, 54, 57]	Event - Implementation of tenting for contamination control may require a modification. Activities that may cause loose/airborne contamination include use of an arter grinder for valve overhaul. This may affect windows: 29, 48, 54, 57, 103, 104, 122, 124, 131 Cause - Procedures drive the requirement for a temporary modification. Impact - Cost impact due to additional resources needed for TMOD.	104		104 - Vault Projects Before Feeder Removal												
			122		122 - Moderator Valve Rehab												
			124		124 - SDC Rm Work												
			131		131 - REMOVAL Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73761																	
13307	Project 73761 - Preventive Maintenance "Other" Schedule Risk [Window 29, 60, 133, 90]	Event - Changes in the level 3 schedule are required due to schedule integration. When the RFP was sent out for the preventive maintenance work, assumptions were made as to when the work would be performed. Due to the numerous systems involved in the preventive maintenance work the scheduling of this work will need to work around and with many other projects. The estimates given were based on the information given in the Scope of Work which may not be accurate once the schedule is integrated. This may negatively affect the cost to do the work. Cause - Schedule integration. Impact - Schedule and cost impacts.	1	Active	Gary Grahn	Greg Mills	16-Dec-16	Accept	31-Jan-17	2	2	2	4	2	1	1	2
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			060		060 - HT Pump Motor Installation												
			090		090 - HTS Operational Testing												
			133		133 - RTS Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13355	Preventive Maintenance -"Other" Parts Risk	Event - Parts required which are no longer available. This may require design changes to be done. Also delays in obtaining parts may push the scheduled tasks requiring a lengthening of the work window or re-establishing the required plant conditions to perform the maintenance. Cause - Obsolete parts Impact - OPG is performing engineering function for this work, may require additional resources.	2	Active	Gary Grahn	Greg Mills	22-Nov-16	Monitor	31-Jan-17	4	1	1	4	4	1	1	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73762																	
14825	Conventional Electrical (Project # 73618) SF6 scope risk	During the kick off with Hydro One on the SF6 scope of work, it was noted by Hydro One that they have been consulted by Siemens (OEM of the SF6 equipment). The result of the consultation of the Siemens technical representative has resulted in significant work to the Hydraulic seals of the SF6 breakers, The seal have reach the end of their life and are being replaced during the same time as the Unit 2 Refurbishment. The scope involves 16 breakers in total for Hydro One. The key risk here is that on the OPG side of the demarcation point there are (4) Breakers that would require the Hydraulic Seals replaced as well. This would be a 4 unit risk as this equipment is cresting on 30 years of service with out any maintenance.	3	Active	Marcus Sztrimbely	Greg Mills	23-Dec-16	Transfer	31-Mar-17	2	2	2	4	1	1	1	1
			Outage Window		**Window Description**												
			132		132 - INSPECT & INSTALL Segment PMs & Misc Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15108	Project 73762 - Risk of Emergent Maintenance work while Refurbishment owns transformers for 2.5 years [Window 130, 131, 132, 137]	It has already become apparent that for the period of time that the Refurbishment will own each unit, any emerging transformer maintenance work will have to be added to the scope of the AREVA maintenance contract. As such, costs for this work will likely increase throughout the life of the contract as miscellaneous maintenance issues arise. At the time of writing, the U2 UST is experiencing an oil leak from the tap changer, and there is a relay which needs to have troubleshooting work done in order to determine whether the relay has failed or not. Rather than to say the risk has been realized, it needs to be understood that this is just the beginning (first 4 months) of the refurbishment period. There is another 2 years in which to maintain these large transformers.	3	Active	Marcus Sztrimbely	Greg Mills	13-Jan-17	Monitor	01-Sep-19	2	2	2	4	2	2	2	4
			Outage Window		**Window Description**												
			004		004 - MOT/UST/IPB Rehab												
			130		130 - LEAD IN Segment PMs & Miscellaneous Work												
			131		131 - REMOVAL Segment PMs & Miscellaneous Work												
			132		132 - INSPECT & INSTALL Segment PMs & Misc Work												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14638	PM Electrical (Project # 73762) Risk of emergent NICRs [Window 004, 041]	As a result of assessments of PM and OA work orders that are part of project 73762, there is a risk of NICRs required to support work where components are obsolete and therefore no longer available commercially. In these cases NICRs will be required to support alternate models that are now the only alternative offered by OEMs. Assessment of this work is complete, however procurement is still underway. Until all items are under order by PO, there is a chance that items will be unavailable. This risk needs to remain open until then.	3	Active	Scott Guthrie	Greg Mills	06-Mar-17	Monitor	28-Apr-17	1	2	1	2	1	2	1	2
			Outage Window		**Window Description**												
			004		004 - MOT/UST/IPB Rehab												
			041		041 - Class 3 Electrical Maintenance												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Balance of Plant - 73773																	
15042	delays of the ASDC pump-motor assemblies and possible impact on Refurb Critical Path	ASDC pumps mounting base plate holes pattern is required to be provided to KSB (Germany) by Dec 28, 2016. If the holes pattern is not submitted to KSB by 28 Dec 2016, the next date they may be able to be submitted is Oct 2017. The pump-motor-assemblies delivery date will be delayed with one year, placing ASDC field execution outside of the installation window 124 (DN Refurbishment outage)		Active	Katie Stewart	Doina Idita	03-Mar-17	Mitigate	30-Nov-17	5	1	5	25	5	1	5	25
			Outage Window		**Window Description**												
			130		130 - LEAD IN Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14368	Potential delay of delivery ASDC pump-motor assembly(mounting hole details) [Window 130, 124]	KSB design of the mounting base plate of the ASDC pump-motor assembly has been changed due to the post welding thermal treatment requirements. Currently the mounting base plate is forged into the pump casing, and being part of the pressure boundary component. The anchors holes shall be machined in to the pump mounting base plate at KSB site. No changes to the holes could be done at ES FOX/OPG site. The prints of the both pumps P4 & P5 anchors as installed in field should be provided to KSB by Dec 30, 2016, with no impact on the delivery date of the pump-motor assemblies. 1. There is a risk of having approx. one month delivery delay if the holes location change from the original design(from Oct 4 to Nov 4, 2017)1. There is a risk of having delivery delays of the pump-motor assemblies if required prints of the installed anchors will not be provided to KSB by Dec 30, 2016.2. There is a risk of having one or more failures of the pull test performed on the installed pumps′ anchors. If the risk occurs then the following will be impacted:- the mechanical EC128660 shall be revised (changing the pump-motor supporting design by having rods perforating the 1.2 meters slab. There will be interferences with SDC HX1 replacement). Cost and schedule impacted - delays in delivery of the pump motor assemblies- missing the installation window (SDC rooms work - within U2 refurbishment outage)- U2 Refurbishment outage critical path may be impacted	4	Active	Katie Stewart	Doina Idita	31-Jan-17	Mitigate	30-Nov-17	4	2	4	16	3	2	4	12
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14368	Potential delay of delivery ASDC pump-motor assembly(mounting hole details) [Window 130, 124]	KSB design of the mounting base plate of the ASDC pump-motor assembly has been changed due to the post welding thermal treatment requirements. Currently the mounting base plate is forged into the pump casing, and being part of the pressure boundary component. The anchors holes shall be machined in to the pump mounting base plate at KSB site. No changes to the holes could be done at ES FOX/OPG site. The prints of the both pumps P4 & P5 anchors as installed in field should be provided to KSB by Dec 30, 2016, with no impact on the delivery date of the pump-motor assemblies. 1. There is a risk of having approx. one month delivery delay if the holes location change from the original design(from Oct 4 to Nov 4, 2017)1. There is a risk of having delivery delays of the pump-motor assemblies if required prints of the installed anchors will not be provided to KSB by Dec 30, 2016.2. There is a risk of having one or more failures of the pull test performed on the installed pumps′ anchors. If the risk occurs then the following will be impacted:- the mechanical EC128660 shall be revised (changing the pump-motor supporting design by having rods perforating the 1.2 meters slab. There will be interferences with SDC HX1 replacement). Cost and schedule impacted - delays in delivery of the pump motor assemblies- missing the installation window (SDC rooms work - within U2 refurbishment outage)- U2 Refurbishment outage critical path may be impacted	6830	In Progress	ASDC project - Civil Design to identify rebar contraints for installation of ceiling anchors	In order to mitigate rebar interference with ASDC pump anchor installation design is requested to evaluate allowable number of rebar that could be cut during anchor installation.	Katie Stewart	Doina Idita	20-Apr-17								

Date has been extended to Feb 28, 2017. Design is reviewing what is req'd to perform this assessment, an initial assessment will be req'd prior to drilling anchor holes in ceiling. Based on more detailed rebar scans and actual field conditions further assessment will be req'd during the actual field installation of the ceiling anchors which was delayed due to the issues on the materials for P4&P5 interferences relocation Date extended to May 30, Design is reviewing what is req'd to perform this assessment, an initial assessment will be req'd prior to drilling anchor holes in ceiling. Based on more detailed rebar scans and actual field conditions further assessment will be req'd during the actual field installation of the ceiling anchors.
Action extended to June 30/16. Fox Director of Design (M. Ismail) to follow-up with new Refurb Design Authority to confirm extent of margin available wrt rebar. Note - rebar scanning to be completed by June 10/16. Update July 5/16: Rebar assessment will be performed by Amec once more detailed scans are completed TCD July 18, 2016
Aug: 30, 2016: Action extended to September 30. work in progress between ES Fox and NR Design Authority to confirm the extent of margin available with respect to rebar. AMEC review of the second ceiling scanning results has been delayed due some clarifications required in order to allow them to perform the rebar assessment by Sep 15, 2016.
Oct 06, 2016: EC137042 has been Initiated to address the interference of the Rebar with the anchors/bolts supporting the ASDC pumps. TCD for DEC completion Nov 09,2016
Jan 31, 2017EC 137042 is not yet finalized. The third design option is in progress for ASDC pump anchorage (design option has been identified and agreed upon on Jan 30, 2017). Action plan and TCD will be communicated shortly by AMEC.

Outage Window	Window Description
124	124 - SDC Rm Work
130	130 - LEAD IN Segment PMs & Miscellaneous Work

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13633	ASDCH - Late Materials as a result of late issuance of PO to Manufacturers [Window 130, 124]	There is a risk that due to the late issuance of manfuacturing POs and EC revisions, materials will need to be expedited in order to arrive on time for execution. This will require funding above and beyond the estimated cost of materials.	2	Active	Scott Guthrie	Doina Idita	31-Jan-17	Mitigate	01-May-17	3	2	3	9	2	2	3	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13633	ASDCH - Late Materials as a result of late issuance of PO to Manufacturers [Window 130, 124]	There is a risk that due to the late issuance of manfuacturing POs and EC revisions, materials will need to be expedited in order to arrive on time for execution. This will require funding above and beyond the estimated cost of materials.	6606	In Progress	Action ESFOX to issue POs for ASDCH components/equipment to obtain vendor information	Engage installation vendor to issue the POs for the ASDCH components/equipment in the very next futrure (ASAP), get the required vendors'information, and finalyze the Design Commissioning Specification, installation and commissioning work plans	Katie Stewart	Doina Idita	15-Mar-17								

Date extended to May 20 to account for new Engineering baseline schedule received for Design revisions. Update 05.13.16: 2nd Extension to June 10 required, ES Fox confirmed that all vendor docs required to proceed with design revisions will be submitted by June 10.
June 13/16 Update - Date extended to June 30 as PE continues to be away (since mid April) writing R&FR workplans and PM is on OCC until June 20.
July 5 update - date moved to continue monitoring. We now have vendor drawings TCDs incorporated into engineering schedule, continue to monitor progress
Aug 5 update - date moved due to the clarifications requested by equipment vendors with respect to the different Design Specification items. All these discussions are part of the vendors' bids evaluation.
Nov 21, 2016: date moved due to the Design Specifications and DECs revision. DBOMs have been modified by adding new components.
Jan 31, 2017As communicated to ES FOX via funding release memo for phase 2B execution, POs for all materials required for ASDC installation shall be issued by April 4, 2017.

Outage Window	Window Description
124	124 - SDC Rm Work
130	130 - LEAD IN Segment PMs & Miscellaneous Work

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13944	ASDCH - Lack of equipment vendors' information causing rework [Window 130, 124]	Due to the lack of manufacturers'/vendors' details/information on numerous components/equipment there is a risk of re-work on design EC packages which implies cost increase for their revision.	3	Active	Katie Stewart	Doina Idita	01-Mar-17	Mitigate	31-Aug-17	3	2	3	9	2	2	1	4

Outage Window	Window Description
124	124 - SDC Rm Work

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14322	ASDC pump-motor site testing [Window 90]	The risk is that the ASDC pump-motor assemblies will fail on site acceptance testing after the factory acceptance testing in Germany. .		Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	30-Jun-19	2	2	4	8	2	2	4	8

Outage Window	Window Description
090	090 - HTS Operational Testing

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13637	ASDCH - Final TSSA registration of Stress Analysis will cause rework to design [Window 124]	ASDC TSSA Registration carried through design completion is provisional, as the stress analysis performed made several assumptions to defer incorporation of Level D Waterhammer, LRV Loads, SDC HXs replacement, EHS modification. There is a risk of: 1. rework of the ASDC final stress analysis to include the above as required for the final registration of the modification. This final stress analysis shall include the stress signals of the other modifications (LRV, SDC HXs replacements, EHS, LDWH and NB3200 analysis). Impact is additional cost to design. 2. potential change in pipe schedule to Class 1, additional supports or reconfiguration of supports. Impact is additional cost to design as well as procurement	1	Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	10-Jul-17	2	2	3	6	2	2	3	6

Outage Window	Window Description
124	124 - SDC Rm Work

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13939	ASDCH - Multilin 239 relay installed on the 600V circuit breaker (supplying the ASDCH pump-motors) to fail the vibration test [Window 41]	As per current design the ASDC pump-motors are supplied from BU13 and BU14 Class III 600V power supply. Because the motor protective relay Multilin 139 (used on both OPG sites Pickering and Darlington NGS) is declared obsolete item, the current design includes the usage of Multilin 239 (MM239) protective relay installed on the 600V circuit breaker unit. There is a risk that the Multilin 239 relay installed on the 600V circuit breaker (supplying the ASDCH pump-motors) to fail the endurance test (testing the functional behavior of the MM239 during 100 cycles open-close of the circuit breaker). This assembly is a "first of a kind" design for DNGS. If the risk occurs, than the associated Electrical design EC's for pump-motor protection shall be changed by placing the Multilin 239 relay in another location.	3	Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	01-Jun-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			041		041 - Class 3 Electrical Maintenance												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13994	ASDCH Large volume of project documentation (TPARs/OMs/etc) may be required [Window 90]	As the ASDCH modification is complex, a significant number of new and OPG existing documents must be updated/created (there were identified 120 documents). There is a risk of EPC contract cost increase if ES Fox underestimated the number of the OPG procedures/documentation (non-change papers associated with EC project) which must be marked-up/created due to the implementation of the ASDCH modification.	2	Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	30-Jun-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			090		090 - HTS Operational Testing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14997	New ASDC power supply circuit breakers may not be a good fit for existing CB cells	Schneider Electrical, the manufacturer of the circuit breakers supplying the ASDC pump-motors, expressed their concern of providing an equipment which could not be a good fit for the existent breaker cells. The risk is valid. Schneider request to perform a walk down and take cells measurements was not granted due to the lack of an outage of the Class III BU13 or BU14 power supply.		Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	31-Aug-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			041		041 - Class 3 Electrical Maintenance												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13607	ASDCH - Execution/installation window schedule delays due to work interferenced with JV work [Window 130,124]	The risk is that the Auxiliary Shutdown Cooling project will face schedule delays during the planned work windows due to the interferences with R&FR/JV work. The ASDC project will get delayed due to the JV work being on critical path for a variety of reasons (i.e. 1. removal of the cable trays required for pulling the power supply cables to pump-motors will be performed immediately after installation of the bulkhead, and their re-installation is plan to be done just before the PHT refill or later on, 2. getting access for the ASDC equipment and materials to SDC rooms when R&FR work is at full speed, 3. work interferences in the same area of the vault) which will lead to a contractor stand down resulting in additional cost and schedule delays.	1	Active	Katie Stewart	Doina Idita	31-Jan-17	Monitor	01-Jul-18	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			130		130 - LEAD IN Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14001	ASDCH pump-motor CSA certification at risk to be rejected [Window 124]	KSB Germany works mostly following European standards and codes. There are the following risks to be considered:- KSB request for CSA certification of the ASDCH pump-motor to be rejected. If this risk occurs, then a major design re-work will be required.- of cost increase of the KSB pump-motor for ASDCH due to the CSA certification requirements. KSB needs to engage a third party to prepare a report proving the equivalency between the european (used for manufacturing of the pump-motor assemblies) and north american standards.		Active	Katie Stewart	Doina Idita	13-Oct-16	Monitor	30-Aug-17	2	1	2	4	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6603	In Progress	KSB to engage TUV (Germany equivalent CSA) to prepare a report proving the bridge/equivalency between the european and north american codes/standards	KSB to engage TUV (Germany equivalent CSA) to prepare a report proving the bridge/equivalency between the european and north american codes/standards Update: KSB did not need to engage TUV they are currently working directly with UL who has identified applicable CSA stds that will achieve equivalency through ULL, many of these will be met through MITP. Risk is considered low but will be monitored through to UL listing. This action will not be completed until ULL is received TCD: August 2017	Katie Stewart	Doina Idita	30-Aug-17							
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14320	U2 Refurb Critical Path extension due to the validation of the ASDC heat removal capability [Window 90]	There is a risk of critical path extension if the validation of the ASDC heat removal capability has to be performed during the ASDC commissioning and linked to the AFS of the modification:		Active	Katie Stewart	Doina Idita	13-Oct-16	Monitor	30-Mar-17	2	2	2	4	2	2	2	4
			Outage Window		**Window Description**												
			090		090 - HTS Operational Testing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14325	Condition of any LPSW tie-in pipe work [Window 124]	Due to implementation of the ASDC modification, LPSW piping providing cooling to ACU1 shall be slightly and permanently changed in Room R2-015. There is a risk that the welding of the new tie-ins will not be possible to be performed due to the condition of the existing LPSW pipes (MIC).		Active	Katie Stewart	Doina Idita	13-Oct-16	Monitor	31-Mar-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14339	Risk of design changes/FICs due to rebar scanning results [Window 12, 124]	The risk is that the rebar scanning results for ASDC pump-motor installation and piping supports may trigger design change or FIC. This risk is elevated for NC1 piping, due to low tolerance for FICs. This risk also applies to hitting rebar during installation, despite results of scanning.		Active	Katie Stewart	Doina Idita	21-Nov-16	Monitor	30-Mar-18	2	2	2	4	2	2	2	4
			Outage Window		**Window Description**												
			012		012 - Defuel Reactor												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14321	Failure of the ASDC commissioning criteria/AFS [Window 90]	There is a risk: - that the ASDC commissioning on unit start up will not be successful and will not pass RTS criteria/AFS (due to failure of SAT, not meeting the commissioning acceptance criteria - electrical, mechanical, vibration failures) -Critical path may be affected		Active	Katie Stewart	Doina Idita	13-Oct-16	Monitor	30-Jul-19	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			090		090 - HTS Operational Testing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13632	ASDCH - DBOM revisions due to obsolete materials [Window 130,124]	Should materials be obsoleted during the time between creation of the DBOMs and field installation, there is a possibility of rework on design. The effect to this would be schedule delays to installation and cost increases to revise the design via a FIC or EC rev (whichever will be appropriate).	1	Active	Katie Stewart	Doina Idita	13-Oct-16	Monitor	14-Apr-17	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			124		124 - SDC Rm Work												
			130		130 - LEAD IN Segment PMs & Miscellaneous Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15199	ASDC Installation cost increase due to extensive engineering support required	Installation of the ASDC modification will be performed by ES FOX.. The required engineering support for installation of the modification is provided by AMEC under a separate contract between the two vendors. [redacted]		Active	Katie Stewart	Doina Idita	27-Feb-17	Monitor	30-Jun-18	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			040		040 - Class 2 Electrical Rehab												
			104		104 - Vault Projects Before Feeder Removal												
			105		105 - Vault Projects After Feeder Removal												
			124		124 - SDC Rm Work												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Project: Balance of Plant - 73782

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11864	Unique Components Rehabilitation (Project # 73782) Increased Scope of Cables/EPs Replacement [window 104][window 105]	Life cycle costs and scope for EQ Cable and EP replacement was based on partial U2 and completed U1 inspection findings. Future inspections on following units may result in scope increase or reduction. Scope increase will have schedule and cost impact. This risk updated and cited as part of Gate 3.	3	Active	Marcus Sztrimbely	Greg Mills	07-Mar-17	Monitor	30-Nov-16	2	2	1	4	2	2	1	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6389	In Progress	Review Cable and EP inspection results for U3	Facilitate/expedite Engineering Review of Cable and EP inspection results for U3. This involves reviewing the NIR and EP inspections from the U3 outage.	Ajay Upadhyaya	Greg Mills	31-Mar-17	U3 inspection reviews were concluded before the end of 2015 and it is now May 2016. This review is behind and issue needs to be escalated with management. Date bumped out to June 30. Discussed lack of progress with Neil Yhap. Pushed date to July 29 Meeting held July 19 with Mike Hodges, Greg Mills, Neil Yhap, Gopal Aluri, John Lee. Timeline for review established completing by the end of August. Due date for this action pushed out to September 2, 2016. September 2 update: Engineering busy on higher priority work. Pushed date 1 month. September 28 update: still no traction on engineering reviews. November 22 update: Have received report for U4 on memory stick to be provided to engineering (this was done due to email size restrictions). U3 report review still in progress with John Lee. Moved date to Dec 15. December 12 update: Conference call with engineering held to discuss path forward. U3 draft report contains a much larger number of findings than prior reports. Clarification has been requested. Bumped due date to January 16, 2017. Unless removed, this could add a considerably larger number of cable replacements to U3 scope. Jan 16 update: No opportunity to address since mid-December. Will follow-up. Date moved to Feb 15. Feb 16 update: Updated report on the way back from Kinectrics via thumb drive (size issues). Will be provided to Engineering for their review. These are the U3 results I believe.

Outage Window	Window Description
104	104 - Post Feeder Vault Projects
105	105 - Vault Projects After Feeder Removal

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Defuelling - 73155																	
14685	Closure Plug seating Issues at Reduced PHT Pressure Envelope	Event: Closure plugs may potentially have seating/sealing issues at reduced PHT Pressure (6 MPA) proposed for defuelling Cause: D1641 exposed the risk of increased probability of closure leakage at lowered pressures used for outage fuelling (~6.5MPa vs. ~7.5MPa used previously) Impact: The leakage of closure plugs could push out the window for defueling longer than 113 days and result in costs incurred for replacement D2O.		Active	Sorin Marinescu	Antonio Carito	17-Feb-17	Mitigate	12-Jan-17	3	4	5	15	3	3	4	12
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9629	In Progress	Contingency - Closure Plug Shimming	Based on conceptual discussions with GEH-C, adding shims to closure plug assemblies could be used to counter-act aging and creep in the Nickel face. Contingency is to develop an engineering solution (NICR), develop procedures and demonstrate the concept for future use. Shims may be purchased for future use - decision to be made following commissioning.		Sorin Marinescu	Matthew Moore	24-Mar-17	Jan 16 - Unit 2 testing was not conducted. Instead, an off-line testing program will be performed, with technical analysis for increasing scope of use for shims.						
			9630	In Progress	Contingency - Seal Disc repair by electroplating	Based on recent Fuel Handling maintenance OPEX at Pickering and Darlington, brush electroplating has been used to successfully repair some components. This action is to explore the possibility to use this process to refurbish aged seal discs by applying new Nickel plating. Steps are for FH Maintenance to have a prototype disc fabricated (COMPLETE), then deliver this to GEH-C (COMPLETE), to conduct testing and inspection. Results may be used to qualify the process for potential future usage (subsequent Units)..		Sorin Marinescu	Matthew Moore	24-Mar-17	13-Dec: Disc was delivered to GEH-C for testing. Results expected in February, with path forward determined afterwards.						
			Outage Window		**Window Description**												
			012		012 - Defuel Reactor												
Project: Defuelling - 73159																	
13395	Price Uncertainty in Additional Software/Opdata Scope	EVENT: Additional Opdata work is required to update the Fuel Handling Software system to incorporate the new inverters and Universal Carriers. CAUSE: Introduction of Universal Carriers requires updates to the Opdata system. Opdata changes were re-categorized as Category III Software changes increasing the required V & V rigor and introducing the need for an EC. The system has also received many partial patches over the years increasing the complexity of the system and creating potential for unexpected results in Commissioning. IMPACT: Additional work required by Vendor staff to fulfill OPG Validation and Verification requirements through commissioning would increase the cost of the project.	3	Active	Sorin Marinescu	Antonio Carito	17-Feb-17	Monitor	28-Feb-17	4	2	2	8	4	2	2	8
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Facilities and Infrastructure Projects (Campus Plan) -																	
13587	Refurb laundry shipments plan	The concern is right now Darlington has laundry shipments taken to unit 0 loading bay going through Stores loading docks. If we continue to ship Refurb Laundry that same way it will have major congestion. There is no room now without additional Refurb shipments. Also how do we manage priority laundry shipments between Refurb and Station stock?		Active	Val Bevacqua	Tom Carvin	19-May-16	Mitigate	26-Feb-16	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Not Started, In Progress Actions associated with the risk.														
Project: Facilities and Infrastructure Projects (Campus Plan) - 31555																	
12334	16-31555 D2O Storage Project: Construction Delays Due to Material Ordering Delays	Event: Late placement of purchase orders or long lead times of materials/equipment Cause: Lack of procurement resources Impact: There is a risk that long lead materials (LLM)/Bulk materials will not be ordered/delivered in time to support the construction schedule.	3	Active	Anthony Colella	Constantin Banica	08-Mar-17	Mitigate	28-Feb-17	4	4	2	16	4	4	2	16
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6336	In Progress	Bulk Material Ordered by JV	JV to provide delivery dates which support need dates of recovery schedule. A weekly meeting is held with a dedicated materials management group, with issues being escalated per documented escalation protocol. Weekly meetings are now being held with materials management group. According to latest bulk material procurement report, the JV still has about 200 items to place onto a purchase order.	Anthony Colella	Constantin Banica	31-May-17	-A lot of major equipment has been fabricated and FATs are being performed. -Long lead items are already ordered.						
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14987	16-31555 D20 Storage Project: Commissioning schedule delay due to late submission of design manuals	Delays in issuance of new design manuals by the JV has the potential of affecting dates for issuance of commissioning workplans by OPG. In turn this has the potential to delay execution of commissioning activities.	3	Active	Anthony Colella	Constantin Banica	08-Mar-17	Mitigate	31-May-17	4	3	3	12	3	2	2	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9188	In Progress	Weekly progress meetings to review DM and WP status	Participate in weekly progress meetings to review work status; take corrective actions as required	Anthony Colella	Constantin Banica	30-Jun-17	OPG participates in weekly progress meetings with JV staff involved in design and commissioning activities. [redacted] Good progress has been made on DCS production. [redacted]						
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14996	16-31555 D20 Storage Project: Schedule delay due to required redesign of fire protection/detection system	Initial design of the WA included sprinklers throughout the building. Design inadequacies resulted in challenges to procure and install a sprinkler system. A decision was made by OPG in September 2016 to have a non-sprinklered building. Regulatory approval for alternate compliance introduces a risk to schedule.	3	Active	Anthony Colella	Ron Piggott	08-Mar-17	Mitigate	28-Feb-17	3	1	2	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9197	In Progress	Obtain CNSC approval for fire protection/detection	Obtain CNSC approval for alternate compliance after re-categorizing to non-sprinklered building design.	Constantin Banica	Ron Piggott	30-May-17	Third party was engaged to confirm compliance with the applicable codes. Letter was submitted (Sept 09) to CNSC requesting approval of alternate compliance for the non-sprinklered design. CNSC has provided comments and OPG will submit Fire Hazard Assessment and CCR in Feb 2017. A separate third party review of the FHA/CCR is in progress and will be submitted to CNSC.						
			Outage Window		**Window Description**												
			000		000 – No Window Related												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
Project: Fuel Handling - 73162																	
14631	Discovery of increased schedule windows during detailed execution logic optimization and station stakeholder review for Powertrack impacting project costs [Windows 39,52]	Event: Preparation of detailed Powertrack installation logic includes assumptions that were used for gate 3 estimate Cause: Assumptions from detailed planning phase associated with the installation methodology and scheduling windows for Intermediate Rollers and Cable Replacement to be validated through logic optimization and station stakeholder reviews Impact: Cost and schedule issues found in assumptions increase above estimated amounts		Active	Sorin Marinescu	Peter Frisina	24-Feb-17	Mitigate	28-Sep-18	3	2	5	15	3	2	3	9

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

There are no Draft, Not Started, In Progress Actions associated with the risk.

11980	Execution Delays Due to Scheduling Logic [Window 39, 52]	Event: Power Track execution is deferred from the designated work window Cause: Power Track is not critical path work but requires the Trolley to be taken out of service, Work Control may defer Power Track work in order to complete other work or maintain fueling. Delays could also result from field co-ordination issues. Impact: Any work window deferral will impact both cost and schedule.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	15-Sep-17	4	2	3	12	3	2	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5724	In Progress	Develop a Detailed Implementation, execution, and schedule for Powertrack	Develop a detailed implementation/execution strategy, working with the contractor and involving the required station stakeholders to ensure alignment. Based on this, develop the installation schedule, including execution windows and fuelling receovery windows.	Sorin Marinescu	Greg Maggs	14-Jul-17	Station requesting review of potential switch from T3/4 to T1/2 being Refurbished first causing delays. Validation of installation logic and schedule planned for July/August 2016: 29Jun2016 update Aug. 31/16: Logic optimization in progress to minimize installation windows and dose. Work planning to be updated to reflect this during Q3/4 2016.
5725	In Progress	Installaion Delay strategy for Powertrack	Implement execution strategy and scheduledeveloped by ES MSA vendor. Risk of installation delays cannot be fully mitigated despite implementation plan. Contingency to be utilized, if required, to address.	Sorin Marinescu	Greg Maggs	14-Jul-17	

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

11977	Discovery Work on Power Track Execution [Windows 39, 52]	Event: Discovery Issue during Power Track Execution Cause: Field discovery issues such as configuration management or equipment degradation. Impact: Execution delay to resolve configuration or equipment conditions	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	15-Sep-17	3	2	3	9	1	2	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5726	In Progress	Detailed Work Planning to Address Potential Discovery Work Issues	Project to address potential discovery work issues by involving both contractor and station stakeholders to review and assess potential discovery risks and issues, during detailed work planning.	Sorin Marinescu	Greg Maggs	14-Jul-17	May 30/16: detailed work plans and instructions have been developed by the vendor (ES Fox). Further review and validation to be completed by project and station stakeholders during Q2/3 2016. Sept. 27/16: Action extended based on extension of completion date for detailed work planning.

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

12414	Discoveries during detailed Work Planning for Power Track impacting project costs [Window 39, 52]	Event: Additional requirements for installation are discovered during Detailed work Planning phase example: requirements for end drum replacement (Power Track frame removal required). Cause: Assumptions from contracting phase associated with the installation methodology and scheduling windows could be incorrect causing major changes to be necessary as the detailed work planning is completed. Impact: Cost and schedule increase from the work planning process.	2	Active	Sorin Marinescu	Greg Maggs	24-Feb-17	Mitigate	28-Sep-18	3	3	3	9	1	2	3	3

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5723	In Progress	Validation Strategy and Schedule with Stakeholders	Phase 1 contract has been issued for detailed work planning. Project is to work with ES Fox and station stakeholders to validate the installation methodology and detailed scheduling windows as part of detailed work planning process. Then address any cost and/or schedule impacts resulting from work planning via proejct contingency.	Sorin Marinescu	Greg Maggs	14-Jul-17	Detailed Work Planning phase will continue until CWP's complete including ITP's (June 30th). Validation of installation logic and schedule planned for July/August 2016: 29Jun2016 update Aug. 31/16: Logic optimization in progress to minimize installation windows and dose. Work planning to be updated to reflect this during Q3/4 2016.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
12414	Discoveries during detailed Work Planning for Power Track impacting project costs [Window 39, 52]	Event: Additional requirements for installation are discovered during Detailed work Planning phase example: requirements for end drum replacement (Power Track frame removal required). Cause: Assumptions from contracting phase associated with the															
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
13376	Two Trolleys are unable to maintain Reactor zone levels adequately causing an operational impact [Window 39, 52]	Event: Zone levels in on the operating units drop close to levels tha require derating. Cause: Two Trolleys are unable to maintain Reactor zone levels due to reliability issues. Impact: Station requires longer recovery periods between execution windows, or windows need to be adjusted resulting in cost and schedule impact.		Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	31-May-17	3	2	3	9	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5722	In Progress	Powertrack Implementation Strategy	Project to work with station to incorporate strategy for addressing unit derating, in Powertrack implementation strategy.	Sorin Marinescu	Greg Maggs	31-May-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
14482	Potential Issues Arise Due to Handoffs Between Station and Vendor At The End of Work Windows [Work Window 52 39]	EVENT: Hand offs between Vendor and Station staff are delayed due to Vendor's inability to operate Fuel Handling equipment while properly integrating with Control Room staff to complete required post maintenance testing prior to hand off. CAUSE: Complexity of Fuel Handling system combined with the large number of short windows (2 to 4 days) scheduled could cause minor issues and miscommunications to push the end of work windows. IMPACT: Increase to cost and schedule as any delay in the completion of work windows pushes the start of the next work window and potentially endangers the reactivity levels of the three operating units.		Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	15-Sep-17	3	2	3	9	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7752	In Progress	Develop Fuel Handling Handoff Strategy	Develop a handoff strategy to be used for end of window transition between vendor staff and OPG Fuel Handling staff with input from an relevant stakeholders.	Sorin Marinescu	Andrew Long	15-Mar-17	Sept 19th: Memo draft written, pending approval.							
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
11976	Trolley Refurbishment scope execution impacts Powertrack [Windows 39, 52]	Event: Station staff schedules Trolley refurb work (also performed in the FFAA's) to the work windows designated for Power Track refurbishment adding additional staff to an already tight work environment. Cause: As per the Blue Ribbon initiative Trolley refurb work beign grouped with Power track Refurb. Impact: Both cost and schedule would be impacted if this were to occur as there could be co-ordination/delay issues.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	31-Oct-17	2	2	4	8	1	2	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5727	In Progress	Address Interface Requirements between Refurb and DNGS	Address interface requirements between Refurb and DNGS as part of execution/implementation strategy, regarding trolley refurb (station scope). Then implement any required actions identified in execution/implementation strategy.	Sorin Marinescu	Greg Maggs	28-Feb-17	Interface requirements to be defined following validation of installation logic and schedule, which are planned for July/August 2016: 29Jun2016 update Work Planning to be finalized Dec15 16							
			5728	In Progress	Interface Issues with Trolley Refurb (Station Scope) During Ex	Project to monitor execution and implement contingency if required to address issues during execution.	Sorin Marinescu	Greg Maggs	31-Oct-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
14512	Terminal Blocks Scope Added to Powertrack Refurbishment Project [Windows 39,52]	EVENT: Terminal Block replacement is discovered as necessary during Powertrack Refurbishment Execution.CAUSE: Terminal blocks have developed some issue. During execution, terminal blocks will have to be replaced. Currently work is part of station (blue ribbon) scope. IMPACT: The additional work required could impact the cost and schedule of the project by stretching and or delaying work windows.		Active	Sorin Marinescu	Greg Maggs	24-Feb-17	Mitigate	30-Jun-17	4	1	2	8	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7963	In Progress	Project to perform a pre-installation assessment for terminal block replacement requirements	Project will perform a pre-installation assessment to determine whether the terminal block replacement is required. If it is deemed necessary 30% of total terminal blocks required for both Trolleys will be procured prior to T12 installation, if additional spares are required during installation they will be procured and a sufficient number will be procured for Trolley 34 execution.	Sorin Marinescu	Catalin Butoi	29-Mar-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14632	Potential for utilization of Radiation Shieldlng during Fueling Duct work for Powertrack Execution [Work Window 52 39]	Event: RP discussion with project team regarding shielding for Powertrack work at Deer Creek Impact: Cost and schedule increase above estimated amounts Cause: Additional procurement and execution cost due to potential use of shielding during Fueling Duct work for Powertrack execution. This resulted from development of the detailed ALARA plan and review/feedback from ALARA department.		Active	Sorin Marinescu	Thomas Wong	17-Feb-17	Mitigate	31-May-17	4	2	2	8	3	2	2	6

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

There are no Draft, Not Started, In Progress Actions associated with the risk.

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13381	Re-Assigment of Powertrack Staff to Other ES MSA Projects During Planned Standby Periods [Windows 39, 52]	Event: The Powertrack execution schedule incorporates planned standby periods as part of the execution schedule. This is based on the requirement to return the trolleys to service following each phase of the Powertrack Refurbishment execution, due to operating unit fuelling requirements. Cause: Each Powertrack trolley pair refurbishment is made up of 15 installation windows ranging from 4 to 28 days, with an overall schedule duration of approximately 6 months. In between each installation window, re-assignment of trades staff will need to be addressed. Some of the staff will be assigned to work on preparation for the next installation window or may be re-assigned to other ES MSA projects. Trades staff that are not doing prep work or re-assigned to other ES MSA projects will need to be paid planned standby time. Impact: Planned standby time pay that the project will be responsible for.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Accept	31-Mar-17	3	2	1	6	3	2	1	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5719	In Progress	Develop and Implement a Re-Assignment Strategy	Develop a project specific re-assignment strategy, working with the contractor.	Sorin Marinescu	Greg Maggs	31-May-17	
5720	In Progress	Co-ordinate Re-Assignment Strategy	Co-ordinate trades re-assignment strategy with other Refurb projects and Work Control.	Sorin Marinescu	Greg Maggs	31-Oct-17	

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13609	Powertrack Engineering Support During Execution [Window 39, 52]	Event: Engineering support is required during execution, examples: To modify Power Track frame, scaffolding, or other possible necessary modifications discovered during execution. Cause: Power Track contract is Procurement and Construction, as the project is "Like for Like". Therefore any Engineering support required would likely be provided by OPG engineering and not covered under current contract baseline. Impact: If this risk is realized OPG engineering support will be required, impacting cost and schedule.	2	Active	Sorin Marinescu	Peter Frisina	17-Feb-17	Mitigate	15-Sep-17	3	2	1	6	2	2	1	4

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
052	052 - Power Track 3 & 4 Replacement

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13383	Powertrack field execution requires additional trades staff to be hired and trained due to ALARA requirements for dose impacting project Schedule and Cost [Window 39, 52]	Event: Contractor staff recieve dose that limits their ability to perform RAD work requiring additional trade staff to complete execution work. Cause: Duration of Power Track refurbishment results in staff reaching dose limits Impact: Hiring of additional staff to maintain sufficient staff levels will be an additional cost on the project.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	28-Jul-17	2	2	1	4	1	2	1	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13383	Powertrack field execution requires additional trades staff to be hired and trained due to ALARA requirements for dose impacting project Schedule and Cost [Window 39, 52]	Event: Contractor staff recieve dose that limits their ability to perform RAD work requiring additional trade staff to complete execution work. Cause: Duration of Power Track refurbishment results in staff reaching dose limits Impact: Hiring of additional staff to maintain sufficient staff levels will be an additional cost on the project.	5717	In Progress	Develop ALARA plan with RP and Contractor	Develop ALARA plan with RP and contractor, taking into consideration the required resources and impact on project.	Sorin Marinescu	Greg Maggs	28-Feb-17	Jan. 24/17: ALARA plan currently on hold pending input from OPG RP on proposed shielding options. ALARA plan to be completed in February 2017 and presented to ALARA committee. May 30/16: ALARA plan has been prepared by ES Fox. Further review and validation will be completed as part of the presentation to the Refurb ALARA team, planned in June/July 2016. Execution Logic review is ongoing, the ALARA plan will be updated after the logic is finalized. Aug. 31/16: ALARA plan was presented to ALARA committee, and rework of the plan was requested due to dose being higher than expected. Project team is working with ALARA and ES Fox to revise execution logic and potentially incorporate shielding in the CSA. Nov. 28/16: ALARA plan was updated and presented to the ALARA committee in October 2016. It was agreed to in concept, but required further details such as the shielding design. RP Refurb agreed to extend the action until Jan. 2016, to allow ES Fox to develop the shielding and make further updates to the ALARA plan.								
			5718	In Progress	Ensure Actions from ALARA Plan are Implemented	Project to ensure actions from ALARA plan are properly implemented including implementation of additional staff as required.	Sorin Marinescu	Greg Maggs	30-Jun-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
13435	Identification of Tooling Requiring Modifications to Station [Window 39, 52]	Event: Engineering support is required during work planning to verify design of an anchor point, addition of shieve, or other modification to station identified prior to execution to perform Power Track replacement. Cause: Power Track contract is only Procurement and Construction, as the project is "Like for Like". But modifications may be required to safely install tooling needed to perform replacement. Impact: Unplanned costs due to Engineering support would be required.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Mitigate	31-May-17	2	1	2	4	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5713	In Progress	Implement any Required Modifications for Tooling	If required, implement a plan to address any modifications required for tooling, that were identified during the work planning phase.	Sorin Marinescu	Greg Maggs	31-May-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												
13433	Breathing Air modification does not fully mitigate requirements during Execution [Window 39, 52]	Event: Both Contractor team and Fuel Handling Maintenance and/or station staff working in Fuelling duct at the same time puts a significant load on the breathing air system. Cause: Trolley reliability failure occurs simultaneously with Power Track execution work causing both teams to be forced to work in th Fueling Duct simultaneously. Impact: Cost and schedule may be impacted if Breathing Air cannot support both activities simultaneously thereby increasing the amount of standby time the proejct must pay for Contractor staff.	2	Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Monitor	31-May-17	1	2	2	2	1	2	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5714	In Progress	SDLU Group to address the requirements for Breathing Air m	Breathing Air mods to be planned and implemented to address Fuel Handling requirements during Powertrack execution.	Sorin Marinescu	Greg Maggs	31-May-17								
			Outage Window		**Window Description**												
			039		039 - Power Track 1 & 2 Replacement Window 1												
			052		052 - Power Track 3 & 4 Replacement												

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14486	Utilizing Winch to Pull Chain and Cable out of the FFAA/CSA [Work Windows 52, 39]	EVENT: Use of Winch to pull Powertrack Chains and Cables out of the FFAA and/CSA damage the cables creating a delay in the completion of the work. CAUSE: Cables are in varying states of wear due to age and original design issue of cable knotting over time. IMPACT: There would be an increase to cost and schedule as the window would likely not be completed on time pushing back the following windows and potentially impacting the reactivity levels of the operating units.		Active	Sorin Marinescu	Greg Maggs	17-Feb-17	Monitor	15-Sep-17	1	1	2	2	1	1	2	2

Outage Window	Window Description
039	039 - Power Track 1 & 2 Replacement Window 1
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There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Pre-requisite Projects -																	
11811	Project/Construction relatedFatality/Serious Injury during Readiness (Campus Plan) Phase of project	Risk is that such injuries may affect the project schedule, cause delays, result in financial impact and potential difficulty controlling the outcome (legal).		Active	Dragan Popovic		08-Mar-17	Mitigate	31-Jan-14	2	2	2	4	1	2	2	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Pre-requisite Projects - 31555																	
14287	16-31555 - Building Structural Steel Delivery Dates	Event: Changes to the 100el slab thickness Cause: Design changes to an accepted EC Impact: Late fabrication and delivery of structural steel	4	Active	Anthony Colella	Anthony Colella	08-Feb-17	Mitigate	28-Feb-17	5	2	5	25	2	2	4	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6504	In Progress	16-31555 - Assess impact of structural steel delivery	Management team is actively involved in reviewing erection schedule with the JV, fabricator and erector. Review delivery dates and expedite to meet construction schedule. Discuss second shift and weekend/overtime work to advance delivery dates.	Anthony Colella	Anthony Colella	28-Feb-17	This risk still continues to delay the project. Sequence 7-10 structural steel has been installed and bolt-up is in progress. Sequence 12 is now in progress (Nov. 9th, 2016).								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
12455	16-31555 D2O Storage Project: Quality Issues Resulting from Expedited Construction	Event: Late start of new EPC Vendor and continued construction delays. Cause: Insufficient QA resources to support CWP/ITP development and material verification. Impact: Quality issues due to expedited construction schedule with many activities progressing in parallel.	4	Active	Anthony Colella	Zane Lougheed	08-Feb-17	Mitigate	28-Feb-17	4	3	5	20	3	3	5	15
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6338	In Progress	Update POP with current field activities	Review and update project oversight plan with new status of field work and increased oversight responsibilities including in field, fab shop in Cambridge as well as any major subcontractors of the JV	Anthony Colella	Zane Lougheed	28-Feb-17	The POP was last updated on September 10 2015, weekly meetings are scheduled to manage open items. FE/IMS oversight going to Cambridge weekly to review fabrication completing QA/QC oversight Participating in bulk material procurement, actively engaged in team to assist with placement of purchase orders and review of need dates and expediting as needed. Field oversight of pipe spools and construction work in the basement. Review of the 2-week look aheads daily.							
			6701	In Progress	16-31555 - JV to provide cost of recovery	JV to provide a cost of implementation of the revised recovery schedule that was provided to OPG on June 12, 2016, as well as based on discussions in Jan/Feb 2017.	Anthony Colella		30-Mar-17	Original due date was with schedule provided. The cost of recovery was not submitted and a date of early march was given by JV. [redacted] 4AUG2016: Basis of Estimate expected from the JV by August 12th, 2016. 8MAR2017: A new estimate is expected from the JV by March30th, 2017.								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
13532	16-31555 D2O Storage Project: Transition between engineering vendors	There is a risk that the transition between the two engineering vendors may result in additional costs and schedule due to the state of the Revision 0 design packages. In addition, field support from the new vendor on the previous vendors design may result in additional design changes due to different designers interpretation of codes/standards. This field support could cause construction delays. Also any latent design errors will have to be revised by the new engineering vendor.	3	Active	Anthony Colella	Aninda Dutta Ray	08-Mar-17	Accept	28-Feb-17	4	2	5	20	4	2	5	20
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7743	In Progress	16-31555 - Number of open ITF items	Review ITF by EC with existing OSS team to start to close out open ITF issues.	Anthony Colella	Henry Lo	28-Feb-17	MTL and DTL (both OPG and JV) meet weekly to close out ITF items that have due dates coming soon.							

ONTARIO POWER GENERATION

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13532	16-31555 D2O Storage Project: Transition between engineering vend	There is a risk that the transition between the two engineering vendors may result in additional costs and schedule due to the state of the Revision 0 design packages. In addition, field suppo	**Outage Window**		**Window Description**												
			000		000 – No Window Related												
14177	16-31555 - 11 New Design EC's Completion Date	Event: Late start of new EPC Vendor Cause: Amount of design work to complete including equipment vendor information. Impact: Late procurement/installation/commissioning activities The 11 new DEC's for JV to complete have a completion date (per the latest recovery schedule) of late 2016, threatening the installation and commissioning milestones. Diesel generator EC and multiple software ECs are outstanding and will need constant revisions. Ongoing revisions will cause more delays.	4	Active	Anthony Colella	Paolo Auciello	08-Mar-17	Mitigate	28-Feb-17	4	2	5	20	3	2	5	15
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14175	16-31555 - CWP Production Rate	JV currently has staffing issues which is affecting the production of CWP preparation and QA resources.	4	Active	Anthony Colella	Zane Lougheed	08-Mar-17	Monitor	28-Feb-17	4	2	4	16	2	2	4	8
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14283	16-31555 - D2O storage project - Impact of Construction Delays on Commissioning Activities	Event: The AFS date is at risk due to changes in commissioning strategy and logic and unviability of commissioning resources. Cause: Delays in installation activities and change in focus from receiving PHT water to receiving moderator water. Impact: Unable to store U2 refurbishment Moderator Water in HWMB-WA	3	Active	Anthony Colella	Ron Piggott	08-Feb-17	Mitigate	28-Feb-17	2	2	4	8	2	2	4	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9940	In Progress	Update Commissioning Schedule	Complete a commissioning schedule review and realignment based on available resources and available systems in the WA (EG Power supplies)	Ron Piggott		28-Apr-17								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
12277	16-31555 D2O Storage Project: Risk of Damage to Storage Tank	There is a risk that one or more of the heavy water storage tanks will be damaged prior to being placed in service.	2	Active	Anthony Colella	Anthony Colella	08-Mar-17	Accept	30-Apr-17	1	1	5	5	1	1	5	5
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12377	16-31555 D2O Storage Project: Construction Delays Due to Piping Complexity	There is a risk that the piping design will be difficult to implement in the field due to complexity and congestion issues; this may result in construction delays that impact cost and schedule.	3	Active	Anthony Colella	Zane Lougheed	08-Mar-17	Monitor	20-Jan-17	1	1	3	3	1	1	3	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12108	16-31555 D2O Storage Project: Soil Voiding and/or Sinkhole Issues Due to Dewatering	There is a risk that dewatering activities required to facilite excavation could cause voiding or sinkholes in the vicinity of the building footprint.	3	Active	Anthony Colella	Jeff Ezard	08-Mar-17	Accept	20-Jan-17	1	2	1	2	1	2	1	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15113	16-31555 D20 Storage Project: Changes resulting from shielding analysis	Updated shielding analysis started late (January 2017) and may result in need for further design changes to include shielding material.	3	Active	Anthony Colella	Constantin Banica	08-Mar-17	Mitigate	30-Apr-17	2	1	1	2	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Pre-requisite Projects - 73360																	

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12290	EPG3 - Critical Spare Parts Unavailable for AFS	There is a risk that critical spares may not be available for the scheduled AFS due to the late identification of the spare parts list. The unavailabilty of spare parts would threaten the AFS being completed and a risk to meeting the Refurbishment breaker open commitment.	3	Active	John Ieraci		08-Mar-17	Mitigate	28-Feb-17	4	3	4	16	4	3	3	12

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
3309	In Progress	Obtain Cost & Delivery Schedule For all Project Spare Parts	Project team to obtain costs and schedule of procuring spares by the Vendor and issue PO rev.	John Ieraci		28-Feb-17	Parts lists created and list signed off for Turbine-Generator/Crane and Protection Panel and most sub-systems. Vendor has submitted costs for these spares on these system. Costs and delivery dates to be finalized. OPG to order spares. Contracts in place.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13954	EPG3: Risk to Software Qualification to Category 2	The equipmnent was supplied without adequate documentation to support Cat 2 software qualification. The EPC Vendor has engaged SWI to qualify the EPG3 software/firmware to Cat 2. Some of the required information to complete qualification is either not available or proprietary. This issue could impact anticipated AFS, if not resolved in a timely manner. Extra effort required by ESFL/HSL/SWI could impact cost and schedule.	3	Active	John Ieraci		08-Mar-17	Mitigate	28-Feb-17	3	2	4	12	3	2	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6940	In Progress	Ensure Certain Software Functional Tests are included in the appropriate EPG3 Commissioning Work Plans	The following software functional checks were not tested during the EPG3 FAT test: 1. Lube Oil Header Pressure Low; 2. Generator Protection Fault - (CAT 1); 3. Back Up Lube Oil Pump Fail; As a result, these functional tests must be included in the appropriate EPG3 commissioning work plan and done on site. This is necessary to support software Cat 2 qualification of the associated components.	John Ieraci		28-Feb-17	Commissioning Work Plans I/P and will incorporate the requirements. Final verifications in progress.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14411	EPG3: Vendor Estimate at Completion	[redacted]	3	Active	John Ieraci		08-Mar-17	Monitor	28-Feb-17	4	3	2	12	3	2	2	6

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13950	EPG3: CSA N291 Concrete/Rebar Materials Testing Results Not Acceptable	Late identification that CSA N291 requires concrete batch materials and rebar to be tested per specific requirements. A material testing lab is now engaged, however results are pending. There is a risk that the results will not be acceptable, yet the concrete and rebar has already been placed. This potentially means rework, with the associated impact to Project cost and schedule.	2	Active	John Ieraci		08-Mar-17	Accept	28-Feb-17	1	1	4	4	1	1	4	4

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

Project: Pre-requisite Projects - 73365

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14371	73365 CFVS - There is a risk that the Project EAC will exceed the current Project approved budget	It is forecasted that the Project EAC will exceed the current Project approved budget. The Vendor is continually submitting overtime requests and CTPs and PCAs that are outside of the currently approved budget. This risk will result in additional cost to the project exceeding the approved budget. Approval at Gate 4 or through a CCN will be required to increase project funding.	3	Active	Ralph Stube	Samantha Thurston	08-Mar-17	Mitigate	30-Dec-16	5	3	4	20	5	3	4	20

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14371	73365 CFVS - There is a risk that the Project EAC will exceed the current Project approved budget	It is forecasted that the Project EAC will exceed the current Project approved budget. The Vendor is continually submitting overtime requests and CTPs and PCAs that are outside of the currently approved budget. This risk will result in additional cost to the project exceeding the approved budget. Approval at Gate 4 or through a CCN will be required to increase project funding.	3090	In Progress	CFVS - Increased ES MSA contrator cost estimate	Review vendor costs during weekly quad chart review meeting. Request detailed CTP and PCA information from the vendor. Present PCAs and CTPs to PMOC for review and approval. Request additional funding through a CCF	Samantha Thurston	Samantha Thurston	23-Dec-16									
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14372	73365 CFVS - Risk that the schedule is not realistic to achieve the AFS milestone due to errors in the schedule	The current P6 schedule has multiple issues of concern including incorrect logic, incorrect activity ties, and incorrect durations. During three week lookahead reviews the contractor is constantly reporting that they are fixing logic errors and updating durations to maintain the AFS milestone date. There is a risk that the schedule is not realistic to achieve the AFS milestone due to errors in the schedule.	3	Active	Ralph Stube	Samantha Thurston	08-Mar-17	Mitigate	23-Dec-16	5	2	4	20	5	3	4	20
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12471	73365 CFVS - Lack of schedule float for weather delays	The weather during the spring months can be rainy and windy. If the winds are too high then craning activities cannot be performed. There is a risk that there is insufficient float in the schedule to account for poor weather conditions. If there is insufficient float then activities put on hold due to rain and/or high wind will cause a delay to schedule and increased costs for trades on standby and craning equipment rental.	3	Active	Ralph Stube	Samantha Thurston	08-Mar-17	Monitor	28-Apr-17	4	2	4	16	3	1	4	12
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13265	73365 CFVS venting stack monitoring requirement potential need to purchase new stack monitor	Reactor Safety review of CFVS MDR requirements traceability matrix identified potential need for project to purchase a new stack monitoring portable device. Project action to date was only to obtain isolatable sample points to tie-in a portable device provided by others. Risk is that a new monitor will need to be designed and purchased and installed, or test connected and commissioned prior to AFS. Project is ~ 6 months from final AFS	2	Active	Ralph Stube	Samantha Thurston	08-Mar-17	Monitor	30-Jun-16	2	1	5	10	1	1	5	5
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13265	73365 CFVS venting stack monitoring requirement potential need to purchase new stack monitor	Reactor Safety review of CFVS MDR requirements traceability matrix identified potential need for project to purchase a new stack monitoring portable device. Project action to date was only to obtain isolatable sample points to tie-in a portable device provided by others. Risk is that a new monitor will need to be designed and purchased and installed, or test connected and commissioned prior to AFS. Project is ~ 6 months from final AFS	4899	In Progress	73365 CFVS resolve need for CFVS Project to provide stack monitoring device	Communicate with stakeholders to identify issue and get support for resolving the requirement. 1. Review RTM requirement with design oversight, nuclear safety and emergency planning organizations and 2. Identify issue to steering committee, project and refurbishment engineering line organizations Identify options to meet potential requirement 1. identify potential existing devices and how they could be mobilized and integrated into CFVS procedures 2. identify requirements for device specification and existing equipemtn similar to device to determine potentail cost and schedule Prepare plan to implement if resolution is that a new device will be required	Bill Devlin	Colin Barfoot	08-Apr-16								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14674	Containment Filtered Venting System(CFVS) Project 73365 - Conduit Interference on VB exterior wall	There is a 4" conduit running up the side of the southeast exterior wall of the vacuum building. This is the planned location for the supports for the CFVS exhaust stack. This interference was missed by Design during the detail design phase. The conduit contains strain gauges for pressure testing the vacuum building during construction as well as during select vacuum building outages. If this conduit cannot be relocated then the exhaust stack will need to be relocated which will require redesign and re-fabrication of supports. If the conduit is not removed as soon as possible it will cause a delay to the exhaust stack support installation. The exhaust stack supports are not available for installation and have a planned delivery date of July 20th which is likely to push because material fabrication is behind schedule.	4	Active	Samantha Thurston	Samantha Thurston	08-Mar-17	Mitigate	28-Apr-17	2	1	3	6	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8413	In Progress	Containment Filtered Venting System(CFVS) Project 73365 - VB exterior wall conduit interference	Collaborative effort between vendor, OPG Projects and OPG Station staff to provide a viable path forward for relocation of the VB exterior wall conduit to avoid installation delays to the exhaust stack supports. Walkdown have been completed. HSL engineering is working on design for new conduit supports. OPG CMO is working on locating drawings of the conduit and equipment as well as assisting with required authorization for removal of the conduit. Fox electrical providing input and support for removal of the conduit.	Samantha Thurston	Samantha Thurston	28-Apr-17	August update: walkdowns have been performed. HSL engineering has designed new supports for the conduit relocation. Conduit will be removed and reinstalled as an AFS open action. ES Fox has requested OPG DTL concurrence on removal plan. Sept/Oct Update: Conduit will be rotated south and fixed to the VB using temporary supports. Permanent supports have been ordered and will arrive on site in early November for installation. Nov update: Conduit has been rotated and permanent supports have been ordered. Permanent supports will be installed when the stack installation is complete. March update: Permanent supports have been installed. A terminal strip needs to be reinstalled.				
			Outage Window		**Window Description**												
			000		000 – No Window Related												
12058	73365 CFVS - Containment Filtered Venting System: (CFVS)Access to the work areas	The risk is that access to the work areas may be denied due to delays in obtaining the necessary access permit or changes in the station meaning access to the PRVM is not possible The risk is that the containment tie-in installation may be extended 1 day beyond the scheduled window. The consequence is aligned resources will incurr standby/ delay cost, and if delay is longer than 1 day it could move the scope to another work week (delay of 8 weeks non critical path with a higher cost) .	2	Active	Ralph Stube	Samantha Thurston	08-Mar-17	Mitigate	14-Oct-16	1	2	2	2	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			3185	In Progress	CFVS - Access to PRVM to complete placing CFVS in service activites	Mitigating actions: 1. Develop appropriate CAD models and perform RELAP analysis. 2. conduct installation reviews with the construction group and vendor to examine potential issues. 3. Develop construction alternatives as required. For final placing system in service, plan execution of 1 look per week to minimize impact of delays in no fuel windows needed to obtain PRVM access needed for isolation to do work.	Colin Barfoot	Colin Barfoot	09-Dec-16	Review meeting has been scheduled with Operations and Projects to align on the commissioning execution and required permitry and AFSing.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												

Project: Pre-requisite Projects - 73380

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14424	STOP Project work area interference with other outage work scope for D1711 and RF U2	Event: in D1641 Installed shielding wall and scaffolding to support STOP installation found to be in the way of other outage work Cause: Lack of outage coordination on time and space usage Impact: Interference with other critical work if not sequenced around STOP space requirements potential delays to work and rework if interferences need to be removed to support critical path.	3	Active	Dragan Popovic	Colin Barfoot	08-Mar-17	Mitigate	07-Jul-17	4	2	3	12	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			7014	In Progress	Prepare time and space matrix for used space for transient shielding and scaffolding builds	For the STOP and ESC piping reconfiguration modifications take detailed photographs of the installed scaffolding, tenting and ventilation, shield walls and other transient material that is needed at specific time and places to support ESC STOP modification installation. distribute information to Outage ECTL and refurbishment		Dragan Popovic	Colin Barfoot	09-Jan-18							
			Outage Window		**Window Description**												
			104		104 - Post Feeder Vault Projects												
			134		134 - U1 Outage 2017 (D1711)												
12345	73380 - STOP- installation interferences with existing station equipment which require equipment relocation, removal or redesign of piping or supports	Event: During STOP installation of seismically qualified vent line or class 2 piping and supports or maintenance platform there will be differences in the location of interferences that were not identified during the design phase. Update to risk is need to relocate unit hydrogen igniter potentially in all units (Unit 4 electrical panel was relocated) Cause: Due to equipment location being different between units and access not close enough to determine interferences during STOP design walk downs. Risk Impact: Since the lines are seismicaly analysed it will require a redesign and analysis, with added design costs and potential outage schedule delay	2	Active	Bill Devlin	Colin Barfoot	08-Mar-17	Mitigate	28-Oct-16	3	1	3	9	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			3184	In Progress	STOP - Installation interferences	Mitigating actions: 1. Detailed inspections will be performed as close as possible to the vault ceiling as soon as vault access is available. 2. tasks have been added in outage P6.		Colin Barfoot	Colin Barfoot	28-Oct-18	mitigated for unit 3, in progress for unit 4 installation of STOP modifications.						
			Outage Window		**Window Description**												
			104		104 - Post Feeder Vault Projects												
			134		134 - U1 Outage 2017 (D1711)												
14254	73380 ESC STOP Vault access restrictions delay STOP execution	Event: Vault Access via vault coordinator control limits the number of personnel allowed to be in the vault due to breathing air and emergency egress reasons. Cause: Vault access is provided to work groups based on outage determined priority. Impact: During each outage ESC STOP execution was delayed for several days in aggregate due to priority based access restrictions. Risk is that access delays will add to project and outage critical path.	3	Active	Dragan Popovic	Colin Barfoot	08-Mar-17	Accept	30-Jun-16	3	2	3	9	3	2	2	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			104		104 - Post Feeder Vault Projects												
			134		134 - U1 Outage 2017 (D1711)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14866	ESC STOP Need to replace ESC containment boundary isolators 34110-V1,V15,V16 on U1 and U2 to install pressure pulse mitigation modifications	Event: In D1641 Containment Boundary Isolation valves passed preventing their use as isolation for the ESC pressure mitigation modifications to relocate the pump discharge valves and install new nozzle check valves. This required draining of the ESC piping in the vault for the pump suction isolator V1 and installation of ice plugs in the vault to support replacement of V15, V16. Cause: Isolators are used to support infrequent maintenance on the ESC system outside the vault and seats degrade from normal operation. Isolators can only be tested once the unit is shutdown and moderator cooled so condition of Unit 1 and 2 isolators is not known. Impact: Outage critical path logic best case prepared for D1632 for contingency replacement of these valves identified 125 hours to replace V15 and or V16 plus 50 hours to replace V1 in series before planned modifications work can start in D1641 the evolution took 296 hours and was the outage critical path for days. Impact on schedule if risk comes to play results in increased project cost extending the duration of dedicated crews for execution.	2	Active	Dragan Popovic	Colin Barfoot	08-Mar-17	Accept	30-Sep-18	3	3	2	9	3	3	2	9
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9166	Draft	Prepare for contingency execution of unit 1 and 2 34110V1, V15, V16 replacement if found passing	1. Ensure execution work plans and work order tasks orders include valve isolation test and direct contingency valve replacement 2. Ensure WCTL schedules isolation test as soon as practical and identifies refurbishment window for contingency valve replacements. 3. Ensure OPEX from delays in ice plugging and isolation are identified per the SCR's below		Dragan Popovic	Colin Barfoot	01-May-18							
			Outage Window		**Window Description**												
			105		105 - Vault Projects After Feeder Removal												
14111	73380 - new design scope to address ESC pressure pulses needed for unit 3, 1, 2	Event: Pressure Pulse identified in Unit3 ESC piping system by STOP SIR team will be addressed by Pump discharge piping modifications with a new type nozzle check valve installation. Cause: Risks are associated with short timeline to complete design, work planning , assessing, procurement and execution and with first time use of this type and size of valve at OPG. Impact: design schedule does not support outage readiness milestones, recovery plan will be needed for all remaining units. Additional oversight and direct management with HIT team	3	Active	Dragan Popovic	Colin Barfoot	08-Mar-17	Mitigate	30-Jun-17	3	2	2	6	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			6225	In Progress	Implement ESC Pressure Pulse elimination modifications	Support execution of STOP for pressure pulse elimination modifications in D1641 outage		Ralph Stube	Colin Barfoot	01-Oct-18							
			Outage Window		**Window Description**												
			104		104 - Post Feeder Vault Projects												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
411	73380 - new design scope	Event: Pressure Pulse identified in Unit3 ESC piping system by	134		134 - U1 Outage 2017 (D1711)												
14928	Schedule Acceleration Execution Cost Risk	Event: During D1632 ESC STOP execution had to be accelerated increasing shifts from planned and started 10h to 12 hours with worked through second lunches with support from RP and all interfacing work groups. Cause: D1632 Execution critical path project PHT pump replacement pulled ahead several days making ESC STOP execution critical Path. Impact: Project costing and planned resourcing are based on planned D1711 execution windows and Unit 2 execution window (duration yet to be confirmed) optimized to minimize cost while meeting the required execution timelines. If project cannot accelerate critical path will be impacted.	3	Active	Dragan Popovic	Colin Barfoot	08-Mar-17	Mitigate	30-Jun-17	3	2	2	6	2	1	2	4
			Outage Window		**Window Description**												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14233	73380 - ESC Pressure Pulse Testing - effectiveness of piping an NV change to be commissionioned in each unit	Event: Pressure pulses in ESC system above the design set point of the STOP RD, potential to be different in each unit. Cause: Original design of piping and check valves as measured on Unit 3 ESC Impact: Lack of testing could result in ineffective design solution in that it does not adequately resolve the pressure pulse issue resulting in failure of the STOP rupture disc, or STOP would not be installed or will be isolated, leading to ineffective STOP installation. Risk for requiring EC revision to support testing results different than expected or with lower probability not being able to execution modification due to proximity to setback.		Active	Colin Barfoot		08-Mar-17	Mitigate	31-Aug-17	2	2	2	4	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6397	In Progress	ESC Discharge check valve pressure pulse testing required t	Design for the ESC Pump start time delay requires testing done on each unit.	Dragan Popovic	Colin Barfoot	10-Jul-17								
			Outage Window		**Window Description**												
			104		104 - Post Feeder Vault Projects												
			134		134 - U1 Outage 2017 (D1711)												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Retube and Feeder Replacement -																	
13326	[QUARTERLY MONITORING] Excusable Delays [000 - No Window Related]	Execution Phase: Due to conditions beyond the control of JV and OPG RFR, 5.2 (a) Excusable Delays Section of EPC Agreement explains the condition and the contract terms of excusable delays, which have impacts on Execution phase Schedule. This risk concentrates on delays of more than 3 days. Ensure adherence to contract terms to ensure any costs are allowable per contract.	1	Active	Roy Brown	Cameron Macleod	03-Mar-17	Monitor	01-Jan-26	3	1	5	15	3	1	5	15

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8383	In Progress	Actions in response to Risk 13326 - Excusable Delays	Update 16Aug2016: This action is created to subdivide specific actions as per team meetings within the Construction Team. The following are the areas to explore: - Radiation conditions (tritium, alpha, debris, high activation product concentration, high radioactive debris/particles) higher than expectations causing delays in cleanup (> 3days); Currently, weekly meetings are held with OPG RP/HP and JV HP and Project team to discuss various interface items. See attached RFR-RP Interface items database. This is a live database of current and incoming challenges to address the above mentioned radiation conditions. - Fueling machine stops unexpectedly (> 3days) below the bulkhead of the Unit being refurbished with Labour Force in the vault working on critical path;- Unplanned Fuel Handling activities affecting duct access (> 3days) applicable to critical path refurbishment work in the duct;- Required upgrades/repairs/maintenance to OPG existing facilities (> 3days);- Unexpected operating plant transients with impacts > 3days on critical path; - Delay in completion of work required to be completed by OPG (or its vendors) (> 3days); - Reactor not defueled on time as scheduled by OPG (> 3days); - Delay in Breaker Open milestone (> 3days); - Loss of station power (OPG supply) to run JV equipment / tools (> 3days)- D2O spills (> 3days)- Activities in operating units (including testing and Safety Related System Test of adjacent operating units) causing interruptions in refurbishment work (> 3days)- Vault Equipment Airlock Malfunction causing interruptions in transitions and material movement (> 3days)- CNSC work stoppage (> 3days)- MOL work stoppage not due to JV's negligent work (> 3days) PCD according to 5.2 (a) Excusable Delays (> 3 days)	Ken Brown	Jeffrey Palmateer	30-Sep-26	

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11111	Lack of Change Control and management resulting in unapproved design changes	Execution Phase Risk. Event: There is a risk that lack of Change Control occurs on RFR Tooling leading to unapproved design changes to tooling. Cause: Lack of clarity on Tooling Change Control process/roles/responsibilities during execution phase leading to insufficient authorities approving changes. There is also a challenge to ensure that approved changes are properly implemented in the field on all applicable tools. Impact: Unexpected damage to the reactor or failure to perform tooling function may occur in the Execution Phase causing rework or delays.	3	Active	Michael Hersch	David Kurpjuweit	27-Feb-17	Mitigate	28-Mar-17	4	1	3	12	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

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Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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11111	Lack of Change Control and management resulting in unapproved design changes	Execution Phase Risk. Event: There is a risk that lack of Change Control occurs on RFR Tooling leading to unapproved design changes to tooling. Cause: Lack of clarity on Tooling Change Control process/roles/responsibilities during execution phase leading to insufficient authorities approving changes. There is also a challenge to ensure that approved changes are properly implemented in the field on all applicable tools. Impact: Unexpected damage to the reactor or failure to perform tooling function may occur in the Execution Phase causing rework or delays.	6298	In Progress	RFR Tooling - Configuration Management Plan	Configuration management of tooling is escalating risk based on multiple CAR/NCR/SCR during standby plan, final design acceptance, and FAT tests of production tools during Q4 2015-Q1 2016. Risk #00011111 strategy changed from Monitor to Mitigate. This action is to develop a targeted oversight and mitigation plan for Q1 2016 to execution start Q4 2016 to ensure that JV is managing configuration management in accordance to their ECR process and rolling changes out to field staff. This action is complete when the overisght/mitigation plan for risk 00011111 is ready and in progress.	Michael Hersch	David Kurpjuweit	17-Mar-17									Geary M (27 Feb 2017): New TCD for extent of condition is March 17 2017 Geary M (31 Jan 2017): This action will be closed upon results from extent of condition from JV. Geary M (16 Jan 2017): Due date revised due to delay in review of disposition from JV Oversight activity 493 planned and will be kicked off with the JV within the next 2 weeks. August 18th 2016 - Oversight activity 493 kicked off with JV. JV to start providing required material the week of August 22nd. Sept 21 update - Execution of oversight plan in progress. Findings to be presented to JV for Oct 1/2016 November 2 update - findings presented to JV and discussed. Dispositions under review. November 17 update - C&D sheet on findings returned to JV. Waiting for JV follow up on open items and TCD December 14th update - several items on the C&D sheet are closed, however currently waiting JV response on items still open.

Outage Window	Window Description
071	071 - Trial CT Install
112	112 - PT Sever
113	113 - Sever Bellows
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
118	118 - CT Install Series
119	119 - Fuel Channel Install Series
184	184 - RFR-Waste Volume Reduction
910	910 - RFR Series Tooling

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13338	Not Enough commissioning / training Time for Volume Reduction System in Retube Waste Processing Building (RWPB)	Execution Phase: Event: Due to RWPB construction being late (potential), the risk of not having enough commissioning / training time for Volume Reduction System . Cause: RWPB construction schedule slippage. Impact: Potential for negative impacts on Execution Phase schedule	2	Active	Michael Hersch	Sean Carpenay	27-Feb-17	Mitigate	31-Oct-17	3	1	4	12	2	1	3	6

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score	
13338	Not Enough commissioning / training Time for Volume Reduction System in Retube Waste Processing Building (RWPB)	Execution Phase: Event: Due to RWPB construction being late (potential), the risk of not having enough commissioning / training time for Volume Reduction System . Cause: RWPB construction schedule slippage. Impact: Potential for negative impacts on Execution Phase schedule	8248	In Progress	WTS CWP updated with Mobilization Plan Findings	Waste Tooling System CWP will include all the lessons learned (as field mark-ups) from the Mobilization Plan testing. The CWP will be revised to include series commissioning for the Waste Tooling System.	Michael Hersch	Sean Carpenay	31-Mar-17	Due date pushed to mid-march. S. Carpenay (31 Jan 2017): Due date extended for one month as CWPs for construction purposes have been prioritized and the Operation CWP will be put on HOLD until then. S. Carpenay (16 Jan 2017): Waiting on CWP 0050 to be delivered to OPG for review. CARPENAS 20160920 - The CWPs 010, 038, 039, 040, 041 and 050 will have lessons learned from Mobilization Plan incorporated by the following dates: CWP 010 - TCD Oct 21, 2016 CWP 038 - TCD Oct 24, 2016 CWP 039 - TCD Nov 24, 2016 CWP 040 - TCD Nov 18, 2016 CWP 041 - TCD Nov 23, 2016 CWP 050 - TCD Mar 17, 2016 SCARPENAY- CWPs 0050 and CWP 0010 are currently under review and mobilization plan testing is being incorporated into the CWPs. Once the review is completed and comments incorporated this action will be closed.								
			Outage Window		**Window Description**													
			184		184 - RFR-Waste Volume Reduction													
			522		522 - Retube Waste Processing Building RWPB													
13860	[QUARTERLY MONITORING] Owner Specified Material (OSM) pricing from Unit-to-Unit Procurement [U1, U3, U4] [000 - No Window Related]	[EXECUTION PHASE] EVENT: There is a risk of cost escalation of the OSM pricing. CAUSE: Due to Unit-to-Unit Procurement, vendor price increases, or other external market conditions. IMPACT: Change to budget allocation.	1	Active	Chad Da Maren	David Fennell	23-Feb-17	Mitigate	30-Dec-16	4	3	1	12	3	3	1	9	
			Outage Window		**Window Description**													
			000		000 – No Window Related													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															

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Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13917	Insufficient Tool Quantities or Spares for RFR Execution - all causes	Execution Risk. This risk combines four risks related to Tool Qty and Spares: 13917 Insufficient Tool Qtys (this risk)13566 Frequent Tool Failures13332 Insufficient Tool Maintenance13570 Tool Damage during Transition and Shipping Event: RFR Tool breaks during execution and cannot be readily replaced due to no backup spare Tool available per Part Supply List (PSL). Details of estimated Tool Series failure modes are described in Class 2 estimate risks associated with each series. The individual tool series risks are owned by the Joint Venture (JV). This risk is the residual risk to OPG. This risk also includes the case where tools cannot be readily repaired. Spares parts have been identified by tools designers (sub vendors). Tool failures associated with sufficient spares, quality of maintenance and repair of the tools, as well as shipping and handling to/from/within site are owned by the JV. This risk is the residual risk to OPG. Cause: This risk combines four (4) types of failure modes leading to insufficient tools/spares leading to critical path schedule delay. The tool failure mode was not identified in risks during design and class 2 execution estimate (discovery work or possible tool warranty claim). This is the residual risk from the design and testing. ie PSL insufficient qtys. (orig scope of risk 13917). Tool failures with known failure modes occured more frequently then expected leading to insufficient spare tools or spare parts for repairs. (Risk 13566). Ineffective Practices in Maintaining the Tools. (Risk 13566). Damages to tools during transitions and shipping to site. (Risk 13570). Impact: Schedule delay, potentially long lead items if Tools cannot be repaired and all tools on PSL used.	2	Active	Michael Hersch	Martin Geary	27-Feb-17	Mitigate	15-Sep-19	3	3	4	12	3	3	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5427	In Progress	Evaluate whether additional spare components and training tools are required.	Review spares list with JV Tooling and identify gaps. TCD Q2 2016. Started Q1, 2016. In parallel Review tool maintenance activities with the JV Tool Management Organization (TMO) and identify gaps. TCD Q2 2016. If gaps are identified, evaluate whether additional spare components and training tools are required.	Michael Hersch	Michael Hersch	31-Mar-17	Geary M (27 Feb 2017) - Please note that from PCD 21, JV has indicated there are no changes required to tool quantities. There are still some open items on the C&D sheets for tooling spare parts (waste tool assemblies, RTP air line connectors, clean room tocco unit). Kevin Hill (27Jan2017) - PCD 21 closure now progressing, Lessons Learned document is required to close the final milestone. This deliverable will outline all JV ACERs generated from the program, including increases to the PSL where required. OPG to review and comment to be performed following submission. Herschm (Jan 16, 2017) - Overall completion of review of JV spare parts list is delayed to February due to a detailed review of WTS spare components vs spare assemblies per OPG oversight team comments. JV TCD was early January, but TCD has been pushed to late January. Kevin Hill (23Dec2016) - PCD 21 (Rehearsal/Mobilization Plan) also describes a project supply list (PSL) update as per observations/lessons learned from the program. This deliverable has not been provided to date, and is being tracked as per RMO action 00005428. Collaborative review between RFR tooling group and RFR facilities will be initiated once a commitment date is confirmed by the vendor. Tooling group to provide status on spare quantities review(s). GearyM (22Nov2016): C&D is in progress. Accepted part of it. GearyM (20/OCT/16): All packages except RCC & WTS - Dispositions for Install and Review Tools provided by JV 2nd week of Oct 2016 and under OPG review. JV provided RCC spares list in Oct 2016. OPG review and comment in progress. GearyM: Due date extended as C&D process is ongoing. Hill K - August 2016 -All PCD 25 milestones have now been endorsed and signed -Spare parts are under review as per RMO Action#00006524 -DEC mock up mobilization plan is in progress, where contingency work orders are being developed and tested, Trades personnel are getting hands on exposure and training with the toolset -WTS mobiliz

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13917	Insufficient Tool Quantities or Spares for RFR Execution - all causes	Execution Risk. This risk combines four risks related to Tool Qty and Spares: 13917 Insufficient Tool Qtys (this risk)13566 Frequent Tool Failures13332 Insufficient Tool Maintenance13570 Tool Damage during Transition and Shipping Event: RFR Tool breaks during execution and cannot be readily replaced due to no backup spare Tool available per Part Supply List (PSL). Details of estimated Tool Series failure modes are described in Class 2 estimate risks associated with each series. The individual tool series risks are owned by the Joint Venture (JV). This risk is the residual risk to OPG. This risk also includes the case where tools cannot be readily repaired. Spares parts have been identified by tools designers (sub vendors). Tool failures associated with sufficient spares, quality of maintenance and repair of the tools, as well as shipping and handling to/from/within site are owned by the JV. This risk is the residual risk to OPG. Cause: This risk combines four (4) types of failure modes leading to insufficient tools/spares leading to critical path schedule delay. The tool failure mode was not identified in risks during design and class 2 execution estimate (discovery work or possible tool warranty claim). This is the residual risk from the design and testing. ie PSL insufficient qtys. (orig scope of risk 13917). Tool failures with known failure modes occured more frequently then expected leading to insufficient spare tools or spare parts for repairs. (Risk 13566). Ineffective Practices in Maintaining the Tools. (Risk 13566). Damages to tools during transitions and shipping to site. (Risk 13570). Impact: Schedule delay, potentially long lead items if Tools cannot be repaired and all tools on PSL used.	5428	In Progress	Provide Comments on Mobilization Plan Series	Through the use of C&D sheets, provide comments on Mobilization Plan Individual Series to the JV. OPG team to ensure comments are incorporated into final work instructions and procedures.	Jeffrey Palmateer	Kevin Hill	31-Mar-17									Geary M (27 Feb 2017) - Please note comments have been submitted for all series in Mob plan and ACERs generated. This action to be confirmed closed by completion of PCD 21. Kevin Hill (10Feb2017) - Linked to risk. Kevin Hill (27Jan2017) - PCD 21 closure now progressing, Lessons Learned document is required to close the final milestone. This deliverable will outline all JV ACERs generated from the program, including increases to the PSL where required. OPG to review and comment to be performed following submission. Due date updated to align with final milestone submission TCD, Lessons Learned document submission. Kevin Hill (23Dec2016) - Only remaining rehearsal scope of PCD 21 is hold due to tooling qualification delays - Feeder nozzle prep. tooling. Review of PCD and scoping document underway identifying deliverable gaps in preparation for PCD formal close out. Meeting to be scheduled with OPG project management to review evidencing of deliverables and/or program gaps. November 30, 2016 Update - K. Hill Mobilization plan is ongoing as per published schedule - due date for this action moved forward as oversight will continue until the completion of PCD 21. Updated file attached outlining all rehearsal observations to date. Mobilization oversight have attended all series rehearsal closeout meetings and ensured ACERs are being captured where follow up/mitigating actions are tracked by the vendors program. Series lead oversight team are to ensure timely closeout of ACERs as per the series readiness programs/procedures. END OF UPDATE Last update - Work is ongoing. Observations/Actions coming out of the Rehearsal Plan are being recorded in a consolidated Observation Log Excel Sheet that is updated continually and maintained on SharePoint, as Rehearsals occur. Also, all actions that JV should be taking to address issues observed in Rehearsals are being recorded and sent to the JV on a weekly basis. END OF UPDATE

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13917	Insufficient Tool Quantities or Spares for RFR Execution - all causes	Execution Risk. This risk combines four risks related to Tool Qty and Spares: 13917 Insufficient Tool Qtys (this risk)13566 Frequent Tool Failures13332 Insufficient Tool Maintenance13570 Tool Damage during Transition and Shipping Event: RFR Tool breaks during execution and cannot be readily replaced due to no backup spare Tool available per Part Supply List (PSL). Details of estimated Tool Series failure modes are described in Class 2 estimate risks associated with each series. The individual tool series risks are owned by the Joint Venture (JV). This risk is the residual risk to OPG. This risk also includes the case where tools cannot be readily repaired. Spares parts have been identified by tools designers (sub vendors). Tool failures associated with sufficient spares, quality of maintenance and repair of the tools, as well as shipping and handling to/from/within site are owned by the JV. This risk is the residual risk to OPG. Cause: This risk combines four (4) types of failure modes leading to insufficient tools/spares leading to critical path schedule delay. The tool failure mode was not identified in risks during design and class 2 execution estimate (discovery work or possible tool warranty claim). This is the residual risk from the design and testing. ie PSL insufficient qtys. (orig scope of risk 13917). Tool failures with known failure modes occured more frequently then expected leading to insufficient spare tools or spare parts for repairs. (Risk 13566). Ineffective Practices in Maintaining the Tools. (Risk 13566). Damages to tools during transitions and shipping to site. (Risk 13570). Impact: Schedule delay, potentially long lead items if Tools cannot be repaired and all tools on PSL used.	9346	In Progress	Work with JV to commit to a TCD for PSL revision	Project Supply List (PSL) requires a revision after the milestone Tooling Manufacturing Completed Delivery. Examples include New Fuel Load, Dowel bellows inspection, PCD 37, Corrections to qty's for Candu Installation tools, Dummy Bundle Tooling Removal, RTP Column Handler. Revisions based on Mob Plan/Rehearsal. If NO changes to PSL for Mob Plan, then a letter to Sr. Director is required.	Michael Hersch	Martin Geary	31-Mar-17									M Geary (27 Feb 2017): Due to resourcing at JV, updated PSL report delayed until end of March. M. Geary (31 Jan 2017): Due date extended. Please note, JV has indicated that mob plan has not driven changes to the PSL. OPG has received updated PSL memos and PSL list. OPG has provided comments and is waiting for dispositions and final revision to PSL report. M Geary - 2017/1/16: Draft revised tool project supply list (memos and excel list) received, but formal document revision not yet provided. M Geary - 2016/12/14: Draft revised report to be provided by end of next week. M Geary - 2016/12/05: As per last Tooling PM meeting, JV due to provide TCD for revised report by December 15th. TCD still undetermined. Priority tooling work for JV is the RFS for the tools. M Geary - 11/17/16: completion of RFS memos and signoff are currently a higher priority. Revision of the PSL will be pushed back as a result. Moved due date to accommodate priorities

Outage Window	Window Description
112	112 - PT Sever
113	113 - Sever Bellows
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
118	118 - CT Install Series
119	119 - Fuel Channel Install Series
184	184 - RFR-Waste Volume Reduction

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14164	There is a risk that Liner Spacers and Liner Latch Assemblies will not be available in time for Fuel Channel installation	[Execution Phase] Event: There is a risk that Fuel Channel Liner Spacers and Liner Latch Assemblies manufacturing will be delayed beyond the need by date for execution Cause: The delay is due to time lost through the purchasing and document review/acceptance phase of work (cannot be recovered), and for a longer than expected manufacturing process as proposed by the vendor. Impact: Liner spacer and latch assemblies are required on site prior to the fuel channel installation series which is scheduled for August 2018. [JV Risk 8.133]	3	Active	Chad Da Maren	Geoff Colling	23-Feb-17	Mitigate	02-Feb-17	4	1	3	12	3	1	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8440	In Progress	Mitigating actions to be performed for liner assembly manufacturing	OPG (RFR OSM Group) will perform oversight of the liner assembly manufacturing by being involved in meetings between the Joint Venture and the Laker Energy, being present at Laker's facility during witness and hold points identified in the ITP, and by performing project management routine oversight at Laker to track schedule and production of the liner assemblies.	Chad Da Maren	Geoff Colling	24-Mar-17	18Oct2016 JV received recovery plan on 17Oct2016, they will provide it to OPG for review within a week.

Outage Window	Window Description
119	119 - Fuel Channel Install Series

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13330	RTP first-of-a-kind Installation in Darlington Vault	Execution Phase Risk. Event/Cause/Impact: As results of Retube Tool Platform (RTP) being the first-of-a-kind platform installed in the Darlington vault with various constraints, the risk of more downtime of the installation than planned may occur in Unit 2 with negative impacts on Execution Phase schedule.	1	Active	Jeffrey Palmateer	Samad Kasaai	03-Mar-17	Mitigate	01-Jan-26	3	1	3	9	3	1	3	9
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9336	Not Started	Develop OA for Risk 13330	Develop OA for Risk 13330		Samad Kasaai		28-Oct-16							
			Outage Window	**Window Description**													
			082	082 - RTP Removals, Bridge Replacement													
			101	101 - Remove FM Bridge and Install RTPs													
13610	[QUARTERLY MONITORING] Execution Delays due to quality or fit-up to Reactor Area Bridge Component Replacement [Window 82]	Event: RAB components do not fit during installation. Cause: Work has not been done on some of the Reactor Area Bridge components since the initial installation and minor shifts in the component alignment could result in fit-up failures. Impact: Components that do not fit must be replaced etiher with original parts that have been refurbished or with new parts that would have to be rush ordered both of which would impact the cost and schedule of the project by delaying critical path installation.	2	Active	Roy Brown	Michael Hersch	28-Feb-17	Mitigate	31-May-18	3	1	3	9	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			5342	In Progress	RAB Planning to include pre-installation and installation activities to mitigate delays	Project to work with installation vendor to ensure planning process and CWP's include pre-installation and installation activities to mitigate the risk of installation delays. Example: dimensonal checks on bearings, mechanical components		Sorin Marinescu	Greg Maggs	28-Feb-17	In progress with CWP reviews: 29Jun2016 27Sep2016: Action extended. Final CWP's have not been received.							
			5710	In Progress	Mitigation of Potential Rework Issues	To mitigate rework issues and cost, Project and Supply Chan to work with vendors to ensure necessary quality checks are included in the fabrication process and that CWP's incorporate necessary pre-installation and quality checks.		Sorin Marinescu	Greg Maggs	31-May-18								
			Outage Window	**Window Description**													
			082	082 - RTP Removals, Bridge Replacement													
15014	Delays/Rework due to inadequate Training	[redacted] Impact: Delays and rework during U2 outage		Active	Kevin Hill	Kevin Hill	03-Mar-17	Monitor	01-May-17	3	2	3	9	2	2	2	4
			Outage Window	**Window Description**													
			017	017 - Install ATP and End Fitting Caps - FM Carriage													
			023	023 - Install Bulkheads													
			025	025 - Install Bulkhead Shielding													
			027	027 - Bulk Interferences Removals													
			029	029 - HTS Vac Dry													
			042	042 - Feeder Removal													
			045	045 - Nozzle Inspection & Weld Preparation													
			071	071 - Trial CT Install													
			072	072 - Bellows Inspections													
			074	074 - Calandria Inspection													
			076	076 - Upper Feeder Installation													
			082	082 - RTP Removals, Bridge Replacement													
			083	083 - Lower Feeder Installation													
			088	088 - Bulkhead Removal													
			098	098 - CTI Release													
			101	101 - Remove FM Bridge and Install RTPs													
			111	111 - Feeder Cabinet Removal													
			112	112 - PT Sever													
			113	113 - Sever Bellows													
			114	114 - End Fitting Removal													
			115	115 - Pressure Tube Removal													

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15014	Delays/Rework due to inadequate Training	[redacted] Impact: Delays and rework during U2 outage	116	116 - CTI Removal													
			117	117 - CT Removal													
			118	118 - CT Install Series													
			119	119 - Fuel Channel Install Series													
			180	180 - Upper Feeder Prep													
			182	182 - RFR-Lower Feeder Preparation													
			184	184 - RFR-Waste Volume Reduction													
			185	185 - RFR-Clean Room CT and FC Preps													
			186	186 - RFR-Feeder Cabinet Install Phase 2-4													
			188	188 - RFR-Feeder Cabinet Install Phase 6-7													
			536	536 - Refurb Control Centre (RCC)													
			539	539 - Temporary Power Distribution System (TPDS)													
			910	910 - RFR Series Tooling													
			920	920 - RFR Series Training													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15135	CWP lifecycle maintenance not adhered to due to lack of ownership	If the CWP's are not kept up to date and accurate, they could become critical path and push schedule (time taken to bring them up to date)		Active	Joseph Lefebvre	Joel Phair	24-Feb-17	Monitor	24-Feb-17	3	1	3	9	2	1	1	2
			Outage Window	**Window Description**													
			000	000 – No Window Related													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12322	End Fitting Waste Processing - First Of A Kind (FOAK) risk	Execution Phase Risk: EVENT: Based on EF processing times incorporated into class 2 estimate, waste processing is on critical path during EF removal series (window 165). As a result of the first of a kind nature of the End Fitting waste processing with no existing operating experience, the risk is that the Waste Processing extends the critical path, with negative impacts on the schedule. This OPG risk is the residual of JV risk 26.23 - Unexpected WTS Failures. CAUSE and IMPACT: This section has been revised as EF processing is on critical path. Equipment Reliability - there is more downtime of the tooling system than planned. Due to the radiation hazards, equipment failures may be difficult to troubleshoot and concerns regarding safety may lead to significant delays during execution. Design Requirements call for close to 100% equipment availability, which may be difficult to demontrate in test program.	3	Active	Michael Hersch	Sean Carpenay	27-Feb-17	Monitor	01-Feb-17	2	2	4	8	2	2	4	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9218	In Progress	EF non-sever parallel path	Pursue design and build of full length end fitting waste container and supporting peripheral items (tooling, transportation package, lifting beam).	Sean Carpenay	Tara Dhekney	13-Oct-17	Rahim Lakhani (31JAN2017): Rahim to speak to Tara D. in regards to creating a risk instead of this action. The RFR team is working with NWDE to design and procure new full length end fitting waste containers (EFWC). The mod package, MDR and scope of work for the design scope of the EFWC are approved. An RFP was submitted to proponents on 02NOV2016 and closed on 22NOV2016. No bids were received. The JV, who is accountable for procurement of the waste containers advised that their fabricators are interested in the design scope as well. OPG is looking to pursue engaging the JV for the full design and build scope of the EFWC. A formal letter to direct this scope addition is being prepared by OPG and Financial approvals are being sought: TCD for both is December 16th. Language surrounding JV liability clauses to be captured in the formal letter will be discussed in parallel with financial approvals. The JV provided a verbal estimate to OPG on Nov 28, 2016 for EFWC interface tooling and CWP updates. A kimono session is planned for the week of December 12th to go over the detailed estimate. Numerous meetings have been held at management levels and working levels to ensure prompt stakeholder responsiveness.				

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12322	End Fitting Waste Processing - First Of A Kind (FOAK) risk	Execution Phase Risk: EVENT: Based on EF processing times incorporated into class 2 estimate, waste processing is on critical path during EF removal series (window 165). As a result of the first of a kind nature of the End Fitting waste processing															
			Outage Window	**Window Description**													
			114	114 - End Fitting Removal													
			184	184 - RFR-Waste Volume Reduction													
13333	[QUARTERLY MONITORING] Stop Work Order due to Safety Events	Execution Phase: Event:: OPG stopping the work order(s) may occur Cause: Due to safety events or near-misses (specifically not related to JV's negligent work) Impact: Negative impacts on Execution Phase schedule.	1	Active	Jeffrey Palmateer	Jarrett Gagnon	03-Mar-17	Mitigate	01-Jan-26	4	1	2	8	4	1	2	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5408	In Progress	Reinforce high safety culture	Reinforce high safety culture in the project team to eliminate safety events or near-misses to avoid impacts of Stop Work Orders.	Jeffrey Palmateer		01-Jan-26	2015/07/13: No mitigation cost as this shall be part of normal training. To ensure that there is a strong safety culture within the JV Project Team there are numerous interactions to ensure there is strong communications, interactions such as; There is a scheduled weekly mock-up walk down with a quorum of the both RFR Construction Mangers (JV & OPG) with the Training Area Supervisor and the Safety Representatives Weekly OPG/JV day meeting where safety events or issues are dicussed and tracked SCR's are entered for significant events or occurances; list can be provided if required							
			Outage Window	**Window Description**													
			000	000 – No Window Related													
14680	Vault Periscope scanner head becomes further degraded	[Execution Phase] Event: During the RFR Bulk Interferences windows, the Vault Periscope scanning head is to be removed, stored and re-installed. The Vault Periscope is currently known to have a damaged seal and not have full range of movement. The Vault Periscope Scanning head may become further degraded during removal and reinstallation process. Cause: The OEM for this equipment is now no longer able to support replacement of the part in question. Performance Engineering - Fuel Handling, is currently in discussions with OEM for refurbishment of the scanning head and performing minor repairs if required. Impact: If the Vault periscope Scanning head is further degraded, a system required by Fuel Handling may be less functional than before.	2	Active	Jeffrey Palmateer	Tony Wong	15-Feb-17	Mitigate	07-Apr-19	4	2	1	8	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9057	In Progress	Oversee station fuel handling establishment of scanner head refurbishment contract	Oversee station fuel handling establishment of scanner head refurbishment contract.	Jeffrey Palmateer	Tony Wong	12-May-17	22NOV2016: Station in discussion with Raytheon to perform testing of scanner head on DNGS site. JV in discussions with Station regarding FH setup of rubber area where scanner head will be stored after it is removed and prior to reinstallation. See attached email 17NOV2016. 16JAN2017: [redacted] FH is looking into alternate viewing technologies which will be installed in a subsequent (not U2 refurb) outage. Station FH has requested that if required, JV still to help facilitate hand-off of components to FH for testing/refurbishment. See attached email 10JAN2017. 31JAN2017: Update action due date as Periscope removal is now scheduled to start May 4, 2017.							
			Outage Window	**Window Description**													
			027	027 - Bulk Interferences Removals													
			173	173 - RFR- Bulk Interference Removal													

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15116	Analysis shows Calandria Vessel Fatigue Usage due to Increased Feeder/FC Loads	Event: Higher loads (from original analysis) have created a fatigue usage on the vessel not previously registered by OPG. The original analysis documented that the Calandria Shield Tank Assembly (CSTA) was exempted from detailed fatigue analysis based on the methods of NC-3219.2 per ASME Sec. III 1977, including summer 1977 addendum. OPG would require the ANSYS model to either: demonstrate in greater detail that the CSTA remains exempt from detailed fatigue analysis, or address reactor transients throughout the extended life of the CSTA. Cause: The stress analysis performed during refurbishment has shown increased loads throughout the Feeder and Fuel Channel Assemblies. These higher loads are being transferred into the CSTA. The increased mechanical load stresses have been shown to meet code allowable stresses and at current, would enable design registration of the CSTA with the TSSA in support of refurbishment. Impact: If the design is not registered with the TSSA as-is (showing fatigue usage), the RFR project may continue to fabricate, ship and install calandria tubes (CT) as a CRN has been obtained from the TSSA for the updated CT drawing and TS. However, a finalized design report must be submitted to the TSSA prior to re-start of the unit. Prior to re-start is conservative as the existing submitted report is still a valid design basis for the retubed configuration but a point in time post-re-start exists when FCs have crept axially to a particular length that the current report is not a sufficient basis and requires updated to account for the higher loads at that time. Final CRNs have been obtained for all portions of the Feeder Piping assembly. Therefore, this issue has no impact on manufacturing or installation of feeder related items. A final CRN has been obtained for the Calandria Tube material TS update. Therefore, this issue has no impact on manufacturing or installation of calandria tubes. However, this final CRN must now be revised/updated	2	Active	Chad Da Maren	Andre Sidiropoulos	23-Feb-17	Mitigate	31-May-17	4	2	1	8	3	1	1	3

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9983	Draft	Obtain Executive Concurence to Register Calandria Vessel Registration Update As-Is	Higher stresses on the End Shields have created a fatigue usage on the vessel not previously registered by OPG. The original analysis documented that the vessel assembly was exempted from detailed fatigue analysis based on the methods of NC-3219.2 per ASME Sec. III 1977, including summer 1977 addendum. If the design is registered with the TSSA as-is (showing fatigue usage), OPG program owner's for LCMP & PIP will need to re-review the design package and determine impacts on their programs. OPG Sr. Management concurrence is sought prior to proceeding with registration.	Chad Da Maren	Andre Sidiropoulos	17-Feb-17	
9984	Draft	Obtain Stress Analysis model/inputs for Calandria Vessel Analysis	Engage supply chain/contracts management in investigating if OPG has the rights to the model/inputs based on commercial agreement in place with Joint Venture for specific scope of work. If OPG has rights to the model/inputs, request them from Joint Venture.	Chad Da Maren	Andre Sidiropoulos	17-Feb-17	

Outage Window	Window Description
080	080 - Fill Calandria

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12254	Installation Delays due to Assessment Issues [Window 64, 70]	Event: JV CWP's do not address the field configurations, ITP's and materials. Cause: RFR quality of assessment is less than adequate. Impact: Poor quality assessment could lead to installation issues which would have an impact on both cost and schedule.	1	Active	Roy Brown	Samad Kasaai	03-Mar-17	Mitigate	30-Nov-16	2	2	3	6	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12254	Installation Delays due to Assessment Issues [Window 64, 70]	Event: JV CWP's do not address the field configurations, ITP's and materials. Cause: RFR quality of assessment is less than adequate. Impact: Poor quality assessment could lead to installation issues which would have an impact on both cost and schedule.	2694	In Progress	Actions to avoid cost and schedule impact due to unidentified structural members in front of vault coils	Investigation into potential interferences prior to commencement of field work.	Marc Paiment	Tony Wong	28-Feb-17								

Feb 4, 2015: will be included in installation planning by JV.
Sept. 18/15: Project is co-ordinating a vault walkdown for JV staff to verify installation methodology and any potential interefence issues. A walkdown was attempted earlier in 2015, but JV staff were not given access to the specific locations required. A further walkdown is planned during Q3.
Feb 2016: Project provided feedback to JV in 2015 that Vault Cooler frames can be temporarily removed to allow coil removal and replacement. JV would need to prepare a weld package to document the frame removal and re-installation. OPG has requested that this be addressed as part of the CWP preparation.
May 30/16: JV has prepared CWP's based on removing/installing coils without any significant removal of interferences from the external area of the coils. This will utilize rigging/scaffolding to maneurvre the coils with the ACU enclosure to facilitate the removal/installation process. Further review will be completed as the CWP's are finalized.
Sept. 27/16: Project has not received the finalized CWP's. Action extended.
Nov. 22/16: CWPs to be finalized Dec 15, 2017, with TCD for DF2 sign-off in Jan 2017. Action extended. JV foreman has also committed to walkdown of area at next window of opportunity now that their is Vault Access during the defuel window.
Jan 6, 2017: Action extended as CWP finalization date for West Side ACUs is now Jan 30, 2017. East Side ACU CWPs to be finalized upon completion of work in West Side to capture any relevant OPEX.
31JAN2017: Action extended as CWP finalization date for West Side ACUs is now Feb 28, 2017. East Side ACU CWPs to be finalized upon completion of work in West Side to capture any relevant OPEX.

5735	In Progress	Mitigation of Assessment Risk for Vault Cooler CWPs	OPG to work collaboratively with contractor in preparation and review of CWPs and schedule to ensure installation does not delay project completion. Support to include obtaining all available technical information (drawings, manufacturers manuals, etc.), obtaining input from station and Refurb SME's, and facilitating any required walkdowns.	Sorin Marinescu	Greg Maggs	28-Feb-17		

May 30/16: Project has provided significant amount of OPEX and drawings/photos to the vendor (Aecon). CWP's have been updated to incorporate this information, and further reviews/validations are in progress for completion of the R0 CWP's.
Sept. 27/16: Action extended. Project has not received updated CWP's.

Outage Window	Window Description
003	003 - Secondary Side SG Layup
064	064 - West Side: Vault ACU Replacements
070	070 - East Side: Vault ACU Replacements

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13329	Claims from Retube and Feeder Replacement (RFR) Vendor Not already Covered in the Contract [000 - No Window Related]	Execution Phase: As a result of OPG not meeting its obligations, there are risks of the RFR vendor making claims for additional costs, cost claim from schedule delay not covered in the Contract, in the Execution Phase. Note: there is a similar risk for Definition Phase (risk #12214).	1	Active	Roy Brown	Cameron Macleod	27-Feb-17	Monitor	01-Jan-26	2	3	1	6	2	3	1	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13394	Vault Cooler Scope Change [Window 64, 70]	Event: Station mandates that the split coil design is used for the Vault Cooler refurbishment Cause: Revised split coil design hasbeen partially implemented in the station. Decision may be made to change over to the new design. Impact: There would be an impact on both cost and schedule if the split ocil design were mandated as it would have to be processed as a project scope change.	2	Active	Roy Brown	Peter Frisina	03-Mar-17	Monitor	31-Jul-18	3	2	1	6	3	2	1	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5236	In Progress	Incorporation of Split Coil Design Into Vault Cooler Installation	1) Project to monitor status of station initiative to implement the split coil design. 2) Project to initiate a project change directive if split coil design is implemented by station and brought into Refurb scope. Split coil would be used in selected locations dependent on removal/installation interferences.3) Project to submit PCD to JV for cost and schedule impact, contingency to be utilized.	Sorin Marinescu	Greg Maggs	30-Jun-18							
			Outage Window		**Window Description**												
			064		064 - West Side: Vault ACU Replacements												
			070		070 - East Side: Vault ACU Replacements												
14016	Toolset Modification due to Station Status Documents for Units 1, 3 & 4	[Execution] Event: There is a risk that Station Status Documents (SSD) for units 1,3,4 will reveal anomalies that challenge tooling design or MOD packages. Cause: The station status documents were generated for Unit 2. Upon review of the station status documents, there were anomalies identified that challenged the tooling design which had to be accounted for. The SSD documents for Units 1,3 and 4 are not complete. Impact: Modifications to the toolset or MOD packages may be required. The cost of completion of the station status documents for Units 1,3,4 are considered in the class II estimate. However, the cost of any modifications to the tooling or MODs is unknown.	3	Active	Michael Hersch		23-Feb-17	Monitor	01-Jan-19	3	2	2	6	3	2	2	6
			Outage Window		**Window Description**												
			112		112 - PT Sever												
			113		113 - Sever Bellows												
			114		114 - End Fitting Removal												
			115		115 - Pressure Tube Removal												
			116		116 - CTI Removal												
			117		117 - CT Removal												
			118		118 - CT Install Series												
			119		119 - Fuel Channel Install Series												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14136	RFR Schedule assumptions for reduced RPPE	EVENT: There is a risk that the transition from wearing Plastic Suits inside the vault for RFR work to no plastic suits after bulkhead installation, commissioning and testing is complete will not be planned and communicated to all workers in a timely manner. CAUSE: The RFR project schedule currently recognizes a large portion of work that requires the use of plastic suits. The transition from plastic suits to reduced requirements on RPPE (such as plastic suits) is a process that will require sustained radiological sampling to demonstrate the requirements and risk for plastic suits is no longer necessary. Currently, there is no planned approach and strategy for the relaxation of RPPE post bulkhead commissioning. IMPACT: The schedule and the assumptions made from the project need to be aware and reflect these requirements to ensure a smooth transition with minimal delays is achievable.	2	Active	Johnathon Hash	Ian Edwards	15-Feb-17	Mitigate	01-Jul-17	2	2	3	6	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14136	RFR Schedule assumptions for reduced RPPE	EVENT: There is a risk that the transition from wearing Plastic Suits inside the vault for RFR work to no plastic suits after bulkhead installation, commissioning and testing is complete will not be planned and communicated to all workers in a timely manner. CAUSE: The RFR project schedule currently recognizes a large portion of work that requires the use of plastic suits. The transition from plastic suits to reduced requirements on RPPE (such as plastic suits) is a process that will require sustained radiological sampling to demonstrate the requirements and risk for plastic suits is no longer necessary. Currently, there is no planned approach and strategy for the relaxation of RPPE post bulkhead commissioning. IMPACT: The schedule and the assumptions made from the project need to be aware and reflect these requirements to ensure a smooth transition with minimal delays is achievable.	6924	In Progress	Create and Document Sampling Requirements to Support the Reduction of Required RPPE inside Vault	The action here is for RP to document the sampling requirements and the subsequent results which would enable a planned transition to reduced RPPE. The secondary piece is documenting the sustaining survey requirements to remain in reduced RPPE or to continue to track RPPE reduction pathways. RP owns the documentation and the surveys required to reduce and maintain (to characterize and monitor for change of conditions). The documented path can be achieved by end of August. RP is still working on the sampling / routine survey plans among other critical items which will influence this process. Ultimately, decisions will be based on N-PROC-RA-0025 "Selection of Radiation Personal Protective Equipment"	Johnathon Hash	Ian Edwards	30-Jun-17									(10 Aug; JJ) Development plans for a strategy to enable a planned transition to reduced RPPE requirements for work inside the vault is in progress. (Sep 13; JJ) Initiated discussions with HPD (Joe Zic) to share with them a proposal from Supply Chain (Julian Read) that Supply Chain can approach several potential vendors that manufacture PAPRs to obtain interest in providing OPG with PAPRs that meet RP's Technical Specifications for a PAPR. The vendors can perform the required tests to meet the specs. HPD had no problem with the proposal, however, HPD indicated that they will still need to test and qualify each PAPR to determine if it meets spec before approving it for OPG use. Next steps: (1) Provide tech spec to Supply Chain. (2) for the 2 PAPRs that have been test and approved for OPG use, explore what the use lifecycle management program will look like for these PAPRs. Based on OPEX from the Bruce, the PAPRs were fairly high maintenance and high care items. FYI...PAPRs are being considered by OPG RP as an alternative to Plastic Suit for work requiring a plastic suit (ex: alpha level 3 areas, high airborne contamination areas). As for sampling requirements, NR-RP will deploy appropriate and specific semi-portable instrumentation (ex: iCAMs) to measure area concentration levels of airborne contamination in specific locations to ensure both workers in the local area and outside the local area are well protected from all RP hazards. These monitoring instruments will be mandatory for certain work and will be stipulated in the Radiation Protection Execution Guides (RPEGs) for each window series. In addition to airborne monitoring, smears of equipment surfaces will be performed and analyzed upon system opening to ensure that workers RPPE are selected in accordance with the best available hazards analysis values. The current RP Program will be adhered to for work planning and execution, with specific focus on proven exposure/contamination control methodologies.

Outage Window	Window Description
013	013 - PHT Bulk Drain
023	023 - Install Bulkheads
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
027	027 - Bulk Interferences Removals
029	029 - HTS Vac Dry

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14517	Difficulty Accepting Findings of Calandria Vessel Inspection	Event: There is a risk that findings of the Calandria Vessel inspection may be difficult to accept without being able to rely on a reference sample of acceptable indications. Cause: While acceptance criteria are defined, it will not be possible to take moulds (replicas) of potential indications. Therefore, it may be difficult to judge acceptability based on visual images only. Impact: This could result in the accountable inspection acceptance authority requesting additional inspection be performed, impacting project critical path.	1	Active	David Kurpjuweit	Andre Sidiropoulos	27-Feb-17	Mitigate	25-May-17	2	1	3	6	1	1	3	3

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9072	Draft	Calandria vessel inspection results	Obtain calandria vessel inspection results from other retube campaigns to be used for training and a baseline for inspections.	Ken Brown		01-Mar-17	
9073	Draft	Calandria Vessel inspection procedure	Review calandria vessel inspection procedures with the contractor and identify ambiguous areas for further development.	David Kurpjuweit		01-Mar-17	

Outage Window	Window Description
074	074 - Calandria Inspection

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14850	Annulus Spacer Retrieval resulting in Contamination of Retube Platform	[Execution Phase] Event: An inordinate amount of time to be spent in decontaminating the Retube Tooling platform prior to re-commencement of the EF flask series. In addition, PCD-14 requires that original activated shield plugs be swapped for new shield plugs in parallel with establishment of the vault crane maintenance window 015. Cause: If the PHT Vacuum dry process elevates the loose contamination levels of internal PHT components that will be handled during this portion of the annulus spacer retrieval. In addition, the annulus spacer retrieval tool has been based upon the current design of the tool used during regular SFCR campaigns – the last (and only) annulus spacer retrieval tool was modified based upon CIGAR data that was obtained just previous to the execution of reactor face work. New CIGAR data will NOT be available for the 6 channels that are going to be the subject of the annulus spacer retrieval during Unit 2 Refurb – all available OPEX has been applied to the design of the ASRT cartridges being used for Refurb BUT there still exists the risk that extrapolated data by which the design has been based upon, may be in error leading to ASRT cartridge failure in channel. Impact: Delays on the critical path schedule which can be mitigated by progressive decontamination steps an increased radiation protection surveillance during annulus spacer execution. If OPG F/H cannot complete the swap for new shield plugs in parallel, then there could be a push to the Refurb critical path duration in the order of 6 to 12 hours.		Active	Michael Hersch	Martin Geary	27-Feb-17	Monitor	31-Aug-17	3	1	2	6	1	1	1	1

Outage Window	Window Description
114	114 - End Fitting Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15193	Production items/materials scrapped due to failure of Pre-Production Qualification	Event: There is a risk that production item(s) and/or material (s) may be scrapped if a supplier fails to pass pre-production qualification (PPQ). Cause: In limited cases, suppliers have been granted approval to begin production manufacturing prior to the close-out of PPQ. This approval has been granted by the JV following OPG's Acceptance of a Design Deviation Requests (DDRs) from the applicable requirement within OSM technical specification(s). The basis of these case-by-case Acceptances has been that production may commence as long as production manufacturing does not proceed past an accepted/approved PPQ step. The intention of permitting the start of production is to mitigate the higher risk of suppliers failing to deliver production items/materials in time to support the RFR execution schedule. This risk is intended to document the residual risk of allowing production to commence prior to PPQ close-out. Impact: In the event that a supplier fails PPQ but has already commenced production under an Accepted DDR, the supplier remains accountable contractually for the cost implications of scrapped production item(s)/material(s). The schedule risk tied to suppliers failing PPQ, regardless of whether or not production has commenced, is generically assessed below.	1	Active	Chad Da Maren		23-Feb-17	Monitor	01-May-19	1	1	5	5	1	1	5	5
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11150	[QUARTERLY MONITORING] Risk of Vendor Default/Business Continuity [000 - No Window Related]	Execution Phase: Event: the vendor is unable to meet the contractual obligation Cause: Vendor default. Impact: It may have negative impacts on cost and schedule to rorganize the teams to continue RFR project.	3	Active	Roy Brown	Cameron Macleod	27-Feb-17	Monitor	01-Jan-26	1	2	4	4	1	2	4	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13325	[QUARTERLY MONITORING] Concealed Conditions [000 - No Window Related]	Execution Phase: Due to uncontrolled and unknown conditions inside the vault, especially, those inside the reactor, 4.8 Concealed Conditions Section of the EPC Agreement explains the condition and the contract terms of concealed condition, which can have cost and schedule impacts on Execution Phase. The examples of Concealed Conditions include, but not limited to:- CTSB Inspection Results;- Feeder nozzle found unsatisfactory;- Calandria tube contacting horizontal flux detector when they are moved;- As-built configurations vary from design and drawings, while laser scan and walk down etc. did not identify the variations and the JV had done everything possible;- Permanent bulkhead unexpected repairs identified during NDE;- Unexpected deficiencies of existing EPs in shutdown cooling rooms, after due diligence of JV exercised;- As-found "original construction" feeder flaws uncovered, after JV verification completes but could not identify those feeder flaws earlier;- Unexpected changes to containment boundary from OPG/other vendors may cause interruption to containment isolation pressure test;- Calandria Vessel discovery work requiring new tool and new method to remove the discovery materials;- PT factures longitudinally, resulting in jagged end on the PT	1	Active	Roy Brown	Jeffrey Palmateer	03-Mar-17	Accept	01-Jan-26	1	3	4	4	1	3	4	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13397	Execution delays due to quality or fit-up of vault cooler components results in impact to cost and schedule [Window 64, 70]	Event: Vault Cooler components found to have quality issues making it necessary to perform re-work during installation. Cause: Quality or fit-up issues with Vault Cooler components. Impact: Both cost and schedule would be impacted if re-work had to be performed on the Vault Coolers.		Active	Roy Brown	Peter Frisina	03-Mar-17	Mitigate	31-May-17	2	1	2	4	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5736	In Progress	Mitigation of Material Procurement Risk, Vault Coolers	Project to work collaboratively with Supply Chain to implement an oversight plan for material procurement to ensure that OPG quality Assurance requirements are met.	Sorin Marinescu	Greg Maggs	31-May-17								
			Outage Window		**Window Description**												
			064		064 - West Side: Vault ACU Replacements												
			070		070 - East Side: Vault ACU Replacements												

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13399	Vault Cooler Cat ID exceptions due to changes in material/design results in cost impact to material procurement [No Windows Related]	Event: Significant Cat ID tech specs, or drawings exceptions are found for vault cooler components. Cause: Changes in the material or design by the bendor since the original Cat ID was created Impact: Increased cost due to material/design changes	2	Active	Roy Brown	Peter Frisina	03-Mar-17	Mitigate	17-Aug-17	2	2	2	4	1	2	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5237	In Progress	Strategy to Address Potential Cat ID Exceptions, Vault Coolers	Current vendor quotes do not include significant exceptions. Exceptions identified at time of procurement would need to be evaluated by Plant Design. Project would need to incorporate any additional costs via contingency.	Sorin Marinescu	Greg Maggs	28-Jul-17	A significant number of exceptions were encountered during the RFQ process for the Vault Cooler motors. The PO issuance is pending, the project needs to review the pricing and reconcile against approved funding for these components (from Gate 3/RQE). Aug. 31/16: Vault cooler motor PO was issued, there is no significant impact to Gate 3/RQE costs currently. There could be an issue if motor production fall behind schedule and expediting fees required. To be monitored during Q3/4 2016. 25Oct2016: PO's have been issued for both Vault Cooler motors and ACU coils. Action to be tracked through the procurement phase to address any cost impacts. 28NOV2016: Authorization to start fabrication on motors still pending. Costs impacts to be determined pending resolution of engineering/QA comments.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13422	RE-work and re-installation caused by Quality Issues with RAB Ball screws impacting both project Cost and Schedule [Window 82]	Event: Quality issues with RAB Ball screws are discovered during installation and/or commissioning. Cause: Fabrication quality or fit-up issues with Ball Screws. Impact: Both cost and schedule would be impacted as re-work and re-installation would be required.	2	Active	Roy Brown	Samad Kasaai	03-Mar-17	Mitigate	31-May-18	2	1	2	4	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5176	In Progress	Ball Screws QA to Ensure Quality	The project to implement any additional required oversight identified to minimize installation risks for the ball screw assemblies. This will include ensuring that OPG Supply Chain Quality Assurance is in place during fabrication to ensure all dimensional and quality requirements are met. This is based on past OPEX from Candu refurbishments that had issues with replacement ball screws. Also, following removal of the existing ball screws, maintain them in storage as a back-up option.	Sorin Marinescu	Greg Maggs	31-May-18	
5716	In Progress	Review of Quality Assurance Requirements with focus on RAB Ball Screws	The project will work with Supply Chain to review the Quality Assurance requirements, with a particular focus on RAB Ball Screws.	Sorin Marinescu	Greg Maggs	28-Feb-17	MITP preparation for the Ball Screws is in progress. Project will work with Supply Chain to ensure QA and oversight requirements are met.
9617	Not Started	Existing Ball Screw Storage	Confirm with JV that ?the existing ball-screw is being carefully removed and properly stored	Samad Kasaai		28-Dec-16	

Outage Window	Window Description
082	082 - RTP Removals, Bridge Replacement

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13442	Delays during PHT Vac Dry Process	Execution Phase Risk. Event: PHT Bulk Vacuum Drying window may experience delays in reaching successful completion of PHT vac dry defined by parameters: dew point at PHT suction of -10C, and less than 50Kg for 24hrs of collection in PHT vac dry skid, and 120 Mg of collection. Cause : There are 3 postulated causes: Tooling (PHT Vac dry skid) failures leading to delays - this risk has been successfully mitigated, see closure notes in comments. (Tooling) Challenges to heat PHT envelope for vac dry to assist evaporation and flow (Heating). Challenges to maintain moisture seal of PHT envelope for vac dry (Leaks). In addition, the following logistical concerns are raised through program risk 919 EC not signed, WPL not complete. REFURB Level 1 logic not correctly aligned(conflict between OPG and Vendor ties in schedule). Impact: Potential for delays to critical path since PHT vac dry is near critical path.	2	Active	Jeffrey Palmateer	Samad Kasaai	03-Mar-17	Monitor	28-Apr-17	1	1	4	4	1	1	4	4
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			910		910 - RFR Series Tooling												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13555	Extra Bellows Need Replacement - all units	[Execution Phase] Event: Not enough spare bellows for Unit 2 Cause: During bellows inspection it is possible to find legacy damage to bellows or during construction bellows may be damaged Impact: If bellow damages require replacement above the number of spares planned, there will be a critical path delay and project costs incurred.	1	Active	Chad Da Maren	Cole Stark	23-Feb-17	Mitigate	01-Sep-17	1	1	4	4	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8256	In Progress	Convert Original Spare Bellows to RFR Design	Once drawing update is complete: generate PO, review incoming bid, award work and oversee conversion efforts.	Cole Stark		01-Jul-17	7Mar2017- Procurement seeking 3 bids for work. 6Oct2016 Drawing will be updated by Oct 12. Scope of work development to follow. 18Oct2016 Drawing will be updated and Issued by CANDU by Oct 21, Scope of work development to follow. 1Nov2016 Drawing was updated and issued by CANDU and accepted by OPG, draft scope of work prepared and under review. 15Nov2016 Due date changed to end of January due to other priorities. 29NOV2016: Bellows conversion TS/Code gap reconciliation and scope of work have been finalized. The next step is to secure funding and issue a purchase order to a machine shop to perform a production run of the conversion. 13Dec2016: SOW completed and approved. OPG-FORM-0214 is in process. 20DEC2016: OPG-FORM-0214 preparation remains in-progress. CCF must be prepared for budgeted cost. 24Jan2017: DRAS completed, in process of completing OPG-FORM-0214. 23Feb2017: Targeting to get the RFP out by the end of March 2017.			
			Outage Window		**Window Description**												
			072		072 - Bellows Inspections												

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14319	Spread of Contamination during RFR Waste Processing of crushed PT (possible similar risks to EF/CT/CTI)	Execution Phase Risk: EVENT: There is a residual risks that that there will be spread of loose contamination in the RFR WTS and RWPB, with negative impacts on the schedule and worker dose due to need to cleanup. This residual risks remains despite best practices in RFR WTS design and procedures. CAUSE: This risk is postulated to occur by loose contamination being spread from the PT chute that links the VRS press to the RWC debris cover. There is a 'O-ring' like barrier that seals the connection between the chute and RWC debris cover during PT crushing, however when the chute is retracted, it is speculated that some of the fine particles in the chute would become loose and spread beyond this ring. By design, it is expected that the 'dirty' pins on the WTS lidding station will become contaminated over time as they lift the debris cover. there are separate 'clean' pins for lidding the RWC lids. However, it is speculated that the partly contaminated debris cover will be lifted over clean RWC lids and transfer some of this loose contamination to the clean lids, therefore requiring cleanup. Note that this lidding station is contained inside a large concrete bunker so direct beams are not a concern. IMPACT: Based on OPEX with a similar WTS VRS press used at Lepreau Refurbishment - when PTs were crushed, the loose contamination led to high dose rates in the vault that required significant cleanup. For RFR, the negative impact would be on the schedule for PT removal and worker dose due to need to cleanup loose contamination.	3	Active	Michael Hersch	Sean Carpenay	27-Feb-17	Monitor	15-Nov-17	2	1	2	4	2	1	2	4
			Outage Window		**Window Description**												
			114		114 - End Fitting Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14516	Poor Imagery Results in Repeated Inspections during Calandria Vessel Inspection	Event: Poor imagery from the Calandria Vessel Inspection may cause the accountable inspection acceptance authority to mandate that particular inspections be repeated. Cause: If the accountable inspection acceptance authority is not present to accept inspection images live-time in the RCC, they may ask that particular inspections be repeated if collected images do not give them the necessary clarity to accept the inspection results. Impact: This would impact critical path activities during the execution of the Retube and Feeder Replacement project.	1	Active	David Kurpjuweit	David Kurpjuweit	27-Feb-17	Monitor	25-May-17	1	1	3	3	1	1	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9074	In Progress	CVI inspection Training	OPG to identify who will be the accepting authority for the CVI results and have that individual participate in training activities for the series. Memo to be prepared to delineate OPG vs JV responsibilities.	David Kurpjuweit		01-May-17								
			Outage Window		**Window Description**												
			074		074 - Calandria Inspection												
14561	Discovery of Work During Installation of Junctions Boxes, Causing Both Cost and Schedule Impacts [Work Windows 38 & 82]	Event: Additional work discovered during removal and installation of RAB&C. Cause: Dose over equipment lifetime causes unforeseen failures and requires replacement or repairs. Impact: Schedule could be impacted and the cost of procuring materials required would impact cost and schedule.		Active	Roy Brown	Samad Kasaai	03-Mar-17	Mitigate	15-Aug-26	3	1	1	3	3	1	1	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7958	In Progress	Add Junction Boxes to Reactor Area Bridge and Carriage Refurbishment Scope	A DRAS will be created to add junction box replacement to the scope of the Reactor Area Bridge and Carriage project to ensure all components potentially impacted by radiation exposure are replaced. If approved funding would be transferred along with the scope to cover the replacement.	Sorin Marinescu	Greg Maggs	31-Mar-17	24Jan2017: DRAS has been prepared and submitted to project PM (RFR). Currently waiting for feedback from RFR to proceed.							
			Outage Window		**Window Description**												
			038		038 - Moderator Drained & Flush												
			082		082 - RTP Removals, Bridge Replacement												
14865	Feeder Thermowell Adaptor Schedule may not support Construction Activities	Event: Final working Feeder instrumentation and controls fabrication schedule may not meet the needs of corresponding construction activities. Cause: Delays during procurement efforts causing vendor inability to meet project deadlines are possible causes. Impact: Delay to feeder fabrication and/or construction activities.	4	Active	Chad Da Maren	Cole Stark	23-Feb-17	Mitigate	01-Feb-18	3	1	1	3	2	1	1	2
			Outage Window		**Window Description**												
			180		180 - Upper Feeder Prep												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11476	[QUARTERLY MONITORING] Insufficient Tooling Intellectual Property Escrow	Execution Phase Event: Inability to tackle a Tooling technical issue may occur during the Definition / Execution phases Cause: As a result of Incomplete Engineering Package filing and insufficient documentation of software tools in Intellectual Property (IP)Escrow, combined with a contractor default. Impact:: Negative effects on * RFR schedule * RFR cost	2	Active	Michael Hersch	Martin Geary	27-Feb-17	Monitor	01-Jan-27	1	2	2	2	1	2	2	2

Outage Window	Window Description
071	071 - Trial CT Install
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
118	118 - CT Install Series
119	119 - Fuel Channel Install Series
184	184 - RFR-Waste Volume Reduction

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12428	[QUARTERLY MONITORING] OPG Foreign Material Exclusion (FME) Events Concealed	Execution Phase: Events: FME items sitting inside Concealed Areas that cannot be discovered/identified in Walkdowns may occur during RFR work in Execution Phase Cause: As a result of historical FME events, Impact: Additional inspection / repair activities with negative impacts to * RFR cost * RFR schedule SCR; N-2015-19073 - RFR – Lack of FME Program was filed to identifiy the lack of FME currently in place as practice. For trending; N-2015-22746 - RFR Tooling shipped to DEC from manufacture with visable Foreign Material JV will issue REV-0 of the FME plan as per the meeting on Nov 4th with planning manager - Sebastian Wojewoda. Follow-up by Gerard Edison with JV SME indicated that incororpoartion of comments have been completed and issue date TBD by JV. The JV will require an approved FME plan for the standby plan that has been approved and issued.	3	Active	Roy Brown	Jeffrey Palmateer	03-Mar-17	Accept	01-Jan-26	1	2	2	2	1	2	2	2

Outage Window	Window Description
045	045 - Nozzle Inspection & Weld Preparation
074	074 - Calandria Inspection

There are no Draft, Not Started, In Progress Actions associated with the risk.

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13336	[QUARTERLY MONITORING] Calandria TubeSheet Bore (CTSB) Needs to be Milled	Execution Phase: Event: Calandria Tube Sheet Bore needs to be milledCause: If CTSB is gouged or scratched during the CT Removal, Impact: Negative impacts on Execution schedule.	1	Active	Michael Hersch	Martin Geary	27-Feb-17	Transfer	01-May-18	1	1	2	2	1	1	2	2

Outage Window	Window Description
149	149 - Tubesheet Bore Cleaning

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13425	RAB Cat ID Exceptions due to changes in material/design results in a cost impact to material procurement [Window 82]	Event: Significant Cat ID tech specs, or drawings exceptions are found for RAB Components. Cause: Changes in the material or design by the vendor since the original Cat ID had been created. Impact: Increased cost due to material/design changes being required.		Active	Roy Brown	Samad Kasaai	03-Mar-17	Mitigate	31-May-18	1	2	1	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5715	In Progress	Mitigate Impact to Schedule and Cost Due to Potential Exceptions to Cat ID	Project to work with Supply Chain and Procurement Engineering during procurement process, to assess any Cat ID exceptions identified. Mitigating activities will be determined and the project will then work with Supply Chain to implement actions to mitigate the issues. Ex 1: Design acceptance of deviations. Ex 2: Use of premium time with vendor as required to address exceptions.	Sorin Marinescu	Greg Maggs	31-May-17	

Outage Window	Window Description
082	082 - RTP Removals, Bridge Replacement

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13560	[QUARTERLY MONITORING] Unforeseen Challenges / Complications in installing re-designed components	Execution Phase: Event: Unforeseen challenges / complications in installation of re-designed items may occur Cause: Due to re-design of components such as End Fitting Closure Plugs and Garter Spring Spacers, Impact: Negative impacts on Execution Phase cost and schedule.		Active	Ken Brown	Jeffrey Palmateer	03-Mar-17	Mitigate	15-Oct-16	1	1	2	2	1	1	2	2

Outage Window	Window Description
119	119 - Fuel Channel Install Series

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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Data Refreshed: 07-Mar-17 10:30 PM

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14897	Feeder Support schedule not supporting construction	Event: Final working Feeder supports schedule may not meet the needs of corresponding construction activities. Cause: Delays during procurement and fabrication efforts causing vendor inability to meet project deadlines are possible causes. Impact: Delay to construction activities.	4	Active	Chad Da Maren	Cole Stark	23-Feb-17	Monitor	30-Apr-18	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			180		180 - Upper Feeder Prep												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14937	Defective Work Performed by JV (Rework)	Event: During Execution, there is a risk that defective work will be performed by the JV and may not be discovered by OPG Cause: One of the causes of risk activation is deviating from approved procedures or accepted work practices. Impact: This results in Costs that are not-recoverable or re-claimed.	1	Active	Jeffrey Palmateer	Joseph Lefebvre	24-Feb-17	Monitor	19-Oct-26	1	2	1	2	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9483	In Progress	OPG NDE Oversight / Review of vendors and sub contractors NDE procedures	OPG project oversight will be involved in the procedure review prior to application by competent certified CGSB level II personnel. OPG project oversight will also be performing oversight for the lifecycle of the execution on feeder welding. Knowing that the review of procedures and inspection oversight will be performed by competent personnel will satisfy the questionability.	Joseph Lefebvre	Joel Phair	30-Apr-17	13JAN2017 (Joe Lefebvre): Vendor NDE procedures are undergoing review by project personnel with support from IMS (TCD: 30 March 2017) Oversight plans are being prepared to identify strategic inspection and review (TCD: 30 April 2017)							

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
149327	Defective Work Performed by JV (Rework)	Event: During Execution, there is a risk that defective work will be performed by the JV and may not be discovered by OPG Cause: One of the causes of risk activation is deviating from approved procedures or accepted work practices. Impact: This results in Costs that are not-recoverable or re-claimed.	9574	In Progress	PAUT equipment, process and qualification of personnel	Oversight involvement/review of the PAUT equipment, process and qualification of personnel prior to the regulator demonstration will be included in the oversight plan specific to this work.	Joel Phair	Joel Phair	30-Apr-17								

Joel Phair - 01-30-2017
Bi-weekly PAUT/NDE meeting took place to update the status of the NDE vendor's progress related to schedule. The NDE vendor has shown a 20% increase in overall schedule progress since Dec 20, 2016. Key highlights include:

All task specific work plans (TSWP) and ITPs associated with the manufacture of calibration blocks have been accepted by the JV.
All drawings for the calibration blocks and flaw specimens have been submitted by the NDE/PAUT Vendor.
Expected date for the completion of all blocks and samples is Feb 14th, 2017.
Expectations moving forward:

Liquid Penetrant (LPI) procedure signed off and submitted to OPG for review and return for 02/03/2017.
Radiography (RT) procedure to be submitted to OPG by 02/10/2017.
UT thickness procedure expected to be submitted by the NDE vendor to the JV by 02/10/2017.
PAUT procedure to be updated once calibration blocks and flaw specimens are received and tested.
Joel Phair - 01-13-2017
Meeting with the CNSC took place in order to establish that OPG and the JV are on course for the qualification of the PAUT procedure as well as being prepared and ready for the performance demonstration (required for CNSC approval to use PAUT in lieu of radiography as per AMSE code case N-659-2) slated to take place in early May, 2017.
Nucleom slated to be on site again within the next week to begin working along side the welding PPQ program. This joint effort is designed to establish Nucleom's performance demonstration will as the same time, providing support to the welding PPQ program.
Joel Phair - 12-12-2016
NDE Vendor (Nucleom) arrived to the DEC to begin participating in preliminary testing of sample welds on sample feeder tubing (3.5", 3", 2.5", 2", 1.5") Technicians qualifications have been verified and certifications are up to date. JV NDE SPOC and JV training personnel are in the midst of providing/ensuring that appropriate training and CBT's are completed for tasks to be perf

Outage Window	Window Description
000	000 – No Window Related

Project: Retube and Feeder Replacement - 10000

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14650	Type A Overpack Packages required for Feeder Shipments within Low Level Waste Containers	[Execution Phase] Event:: RFR project has initiated a plan to procure newly designed LLW Type A overpack packages that LLW containers would be placed into for transportation shielding purposes Cause: Through waste planning and estimation the RWN process has identified that Feeders contained within LLW containers will meet Western Waste Management Facility (WWMF) storage acceptance criteria, however these LLW's may not meet Transportation regulations when shipped from DNGS to WWMF. Impact: The following are the impacts: OPG RP has provided extensive calculations noting the transportation requirements may not be met and as a result is included in the attachments Shielded Overpack will need to be designed, licensed, tested and fabricated There is a Financial Impact There is a Logistics Impact	2	Active	Ken Brown	Tara Dhekney	16-Feb-17	Mitigate	30-Apr-17	4	2	3	12	3	1	1	3

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8371	In Progress	Implement Project Management on Overpack Design and Fabrication	Implement Project Management on Overpack Design and Fabrication Please see attached schedule of actions.	Ken Brown	Yung Cheung	15-Jul-17	T. Dhekney (23FEB2017): Project kickoff meeting with Candu took place on Feb. 21, 2017. Candu has advised that they expect to be able to provide 16 overpacks by early July (i.e. before the start of feeder removal series). Contingency plans for late delivery of the overpacks such as on-site storage in RWSB and loading of the feeder waste containers in an ISO-40 are in development. Tara D (16FEB2017): Detailed Engineering by Candu will commence based on letter to proceed. Due Date is changed to mid-july as per latest vendor schedule (based on feeder execution window). 2016-07-26 Cam W: The MOD design and preliminary engineering is underway, along with nuclear waste design engineering.

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14650	Type A Overpack Packages required for Feeder Shipments within Low Level Waste Containers	[Execution Phase] Event:: RFR project has initiated a plan to procure newly designed LLW Type A overpack packages that LLW containers would be placed into for transportation shielding purposes Cause: Through waste planning and estimation the RWN process has identified that Feeders contained within LLW containers will meet Western Waste Management Facility (WWMF) storage acceptance criteria, however these LLW's may not meet Transportation regulations when shipped from DNGS to WWMF. Impact: The following are the impacts: OPG RP has provided extensive calculations noting the transportation requirements may not be met and as a result is included in the attachments Shielded Overpack will need to be designed, licensed, tested and fabricated There is a Financial Impact There is a Logistics Impact	10056	In Progress	Assessing the feasibility of shipping feeders in an ISO 40 container in shielded pallets	An action has been created to assess the feasibility of shipping feeders in an ISO 40 trailer in shielded pallets. Currently, contingency planning is progressing with several alternatives assessed for transportation of the LLW containers, tracked in the attached spreadsheet. This action is to track the primary alternative option identified as a contingency option based on the assessed feasibility.	Tara Dhekney	Patrick Ho	15-Jul-17							

T. Dhekney 22FEB2017:
Plan B - Shielded pallet in an ISO-40:
The Refurb Waste SPOC conducted a feasibility study to assess if the shielded pallet could be loaded into an ISO-40 and proved the concept to be feasible. The team has performed a walkdown of the weather enclosure to look at constraints that might affect loading of an ISO-40. RFR, JV and Refurb Waste SPOC have met with Specialty Handling to discuss opportunities for equipment rentals to facilitate loading of the ISO-40 in the weather enclosure and it appears that the forklift elevator is not feasible given the space constraints in the weather enclosure. the Refurb Waste SPOC has secured the use of a modular ramp (borrowed from the station) for loading in the unzoned area adjacent to U0.

PLAN C - RWSB Temporary Storage
Waste Nuclear Safety has reached out to their preferred third party vendor to discuss an accelerated safety analysis of feeders in the RWSB. The vendor has provided an estimate for the work and RFR is working on securing the funds to get the PO issued.

16FEB207 (Tara D.): Looking at contingency options. They are

Onsite storage (performing nuclear safety assessment and discussing license amendments with CNSC - TCD April 30, 2017)
ISO 40: Trucks to be used in absence of overpacks of shielded Type A overpacks. (RMT group is procuring additional trucks to support RFR and running transportation logistics study to look at different feeder contingencies TCD: July 10, 2017 and Feb 28, 2017). For shielded pallets design and procurement, OPG has submitted Task Order request to third party vendor for shielding analysis (TCD: March 3 2017). Next step is to complete ARRAM
Loading location onsite (Looking at feasibility and weather enclosure TCD: April 30, 2017)

Outage Window	Window Description
042	042 - Feeder Removal

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14687	Interface for Discharging Primary HEPA Filters and VFF Filters into RWC	Execution Phase: Event: Waste processing cannot proceed to discharge filters. Cause: The commercial and contractual issues disrupting the progress of the design and testing of the interface Impact: Negative impact on schedule (work stopped)	3	Active	Ken Brown	Kwok Tsang	24-Feb-17	Monitor	30-Jun-17	3	1	4	12	1	1	1	1

Outage Window	Window Description
184	184 - RFR-Waste Volume Reduction

There are no Draft, Not Started, In Progress Actions associated with the risk.

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13266	Waste - ILW containers for non-standard waste streams	[Execution Phase] Event:: Gap in JV Planning for managing non standard ILW waste streams (VRS press, chute, and VRS/VFF filters) and miscellaneous ILW. Cause: There may be a requirement for ILW containers to be designed for some ILW that are not the standard waste stream. This is identified in the JV document, "RFR Waste Forecast Quarterly Update Report" (509407-0000-00000-40RA-0094) and the Radioactive Waste Notifications (RWN) for the waste streams of interest. Impact: Cost Impact Schedule Impact	3	Active	Tara Dhekney	Yung Cheung	15-Feb-17	Mitigate	31-Jul-16	3	3	2	9	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

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13266	Waste - ILW containers for non-standard waste streams	[Execution Phase] Event:: Gap in JV Planning for managing non standard ILW waste streams (VRS press, chute, and VRS/VFF filters) and miscellaneous ILW. Cause: There may be a requirement for ILW containers to be designed for some ILW that are not the standard waste stream. This is identified in the JV document, "RFR Waste Forecast Quarterly Update Report" (509407-0000-00000-40RA-0094) and the Radioactive Waste Notifications (RWN) for the waste streams of interest. Impact: Cost Impact Schedule Impact	5929	In Progress	The plan for the VRS press and chute	The plan for the press and chute is: 1: Decontaminate in the WTS using CO2 blasting 2: Debris from CO2 blasting will go into a RWC/DSO assembly 3: Following decontamination, the press will be removed and placed in a "strong box". This "strong box" will either be stored on-site or off-site for approximately 10-15 years (after storage period, the press will be size reduced), or will be shipped to a decontamination facility for further decontamination and size reduction. For this plan to be viable, the following concerns will need to be addressed: 1: Impact of decontamination debris in the RWC/DSO assembly (long term storage) 2: Potential and impact of condensation build up during decontamination. There should be no water in the retube waste container. 3: Need specification of the proposed "strong box". At a minimum, this will still need to meet Minstry of Transportation requirements (tie-downs) for on-site transfer. 4: To confirm that the EA and licence of the RWSB can accept the new waste stream.	Yung Cheung	Yung Cheung	31-Mar-17								

25JAN2017: Action is being discussed weekly in the waste forecast meeting. Meeting minutes from 18-Jan have been attached with history of the updates on the action. The following is the latest update:
- No update on the potential 3rd party vendors. JV is still in the process of reaching out to the various vendors. -
The MOU was discussed. JV asked if information on the overpacks such as mass will be included in the MOU. OPG will provide the overpack technical specification document to the JV, so they can plan the overpack logistics.
Update as of November 15, 2016:
The LLW portion of the waste (Press and chute) has been approved by WWMF. THe plan is to place this in the LLWC (Cat ID: 539596) following 3rd party decontamination.
The ILW portion of the waste is pending. Waiting for NWDE to sign off forms.
CO2 blasting was observed at ATS with good results.
Update as of October 3, 2016:
Yung Cheung will be setup as the owner of this risk moving forward as she's interfacing with the JV regularly. Last correspondence was between Yung and Eric Freeman of NWDE asking for compliance verification. Yung will update this risk with her response to Eric.

From: FREEMAN Eric -NUCLEAR Sent: Friday, September 16, 2016 1:29 PMTo: CHEUNG Yung -NUCLEARCc: RAGUNATHAN Sangeeth -NUCLEAR; SATO Jim - NUCLEARSubject: RE: RWSB NWFRs Press & Chute COMPLETED

Yung,

Please let me know if the attached clarifications address the RFR Project's concerns about the acceptance conditions in the NWFRs for the Press and the Chute. If the clarifications are acceptable then I will work with Sangeeth to append the clarifications to the NWFRs.
Regards,

Eric FreemanSection ManagerRadioactive Waste Transportation DesignNuclear Waste Design Engineering DepartmentNuclear Design Engineering DivisionOntario Power Generation Inc. + P84 - A1
Pickering Town Centre 1340 Pickering Parkway
Pickering, Ontario, Canada

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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25JAN2017: Action is being discussed in the weekly waste forecast meeting, meeting minutes have been uploaded as of 18-Jan.
For Misc ILW, the plan has been agreed to obtain new ILW utility containers for storage of the planned Misc ILW. MOD package has been approved, but vendor has yet to be selected. Preferred vendor has been told to prioritize design of the EFWC, meeting with alternative vendor to be scheduled. Contingency planning for misc ILW is in progress, with the plan to use drums for storage.
For the HEPA filters, RFR is to provide a sketch of the possible interface tooling for the JV to proceed. TCD 26-Jan
Update as of October 3, 2016:
JV had engaged ATS (Tooling provider) to design and build this new interface. At the moment conceptual design drawings have been produced with RFR project reviewing.
Michael Hersch will now be put down as Action Owner as his team is well involved with providing oversight for JV and ATS.
August 10, 2016:
Hepa Filter Interface- Risk remains the same however, commercial discussions between OPG RFR and JV are ongoing about pursuing the interface and working out the commercial details later.
Misc. ILW Container - OPG modification paperwork and design specification are proceeding for review by DTL August 11th.

July 27, 2016: OPG are in the process of designing a new Misc. ILW container that will be placed in the vault and used like a garbage can for Misc ILW streams.
Modification outline and technical specification are with NWDE for review.
Alex Lempp is the engineer assigned to this document review which will go to the DA for signatures.
HEPA Filter interface letter should be soon issued by OPG to the JV with regards to obligations of who's to incur cost and complete the design, testing and implementation of interface design.

30May2016: No change.
05 May 16 - The primary HEPA filters and VFF (Vacuum Filter Flask) filters will be going into the RWC. The types of assessments that need to be performed to demon

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Outage Window	Window Description
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
184	184 - RFR-Waste Volume Reduction

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
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13426	[QUARTERLY MONITORING] Restriction for Craft to Enter the Vault	Execution Phase: Event: Imposing restriction on craft to enter the vault may occur Cause: Due to radiological condition (contamination level too high, loss of component, or spikes of radioactivity) Impact: Results in productivity losses and impacting schedule.	1	Active	Roy Brown	Jeff Johansson	03-Mar-17	Monitor	01-Jan-26	3	1	3	9	3	1	3	9

Outage Window	Window Description
023	023 - Install Bulkheads
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
025	025 - Install Bulkhead Shielding
101	101 - Remove FM Bridge and Install RTPs
111	111 - Feeder Cabinet Removal
112	112 - PT Sever
113	113 - Sever Bellows
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
173	173 - RFR- Bulk Interference Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

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12214	[QUARTERLY MONITORING] Claims from Retube and Feeder Replacement (RFR) Engineering, Procurement and Construction (EPC) Vendor [000 - No Window Related]	Definition Phase As a result of OPG not meeting its obligations there are risks of the RFR EPC vendor making claims for additional cost and schedule in the Definition Phase, per article 4 of the Agreement. Note: It will be raised as another risk (#13329) for the Execution Phase.	3	Active	Roy Brown	Cameron Macleod	27-Feb-17	Monitor	31-Jan-17	1	3	4	4	1	2	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2628	In Progress	Engage OPG commercial lead with OPG counterparties on Claims	Engage OPG commercial lead with OPG counterparties on Claims due to OPG not meeting obligations. This process has ramped up throughout the end of Definition Phase as potential claims and commercial issues arise.	Cameron Macleod	Isaac Smith	28-Feb-17	OPG commercial lead with OPG project team on potential Claims due to OPG not meeting obligations. Commercial lead attends regular project management meetings internally and with Contractor where such items could arise. Although the Definition Phase is winding down, this action will continue through Execution Phase. Jan 20 - This process is ongoing - there is a bi-weekly commercial meeting with the JV to discuss and progress commercial issues, including "escalation" issues such as potential claims Feb 27 - This process is ongoing, to add to the bi-weekly meeting above, there are issue-specific meetings scheduled with the JV to close open commercial issue more expeditiously.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
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11584	Waste - Inefficient Waste planning and practices	Execution Phase: Event: 1) Activity of the waste targeted for the containers are higher than assumed preventing the containers from being filled to capacity. 2) The process of loading Intermediate Level Waste into the containers impacts the packing factor. 3) New waste stream arises that no one has considered before 4) Waste that were to be LLW could now be ILW, such as DFBs. Cause: Unplanned waste combined with inefficient practices Impact: negative impact on both schedule and cost.	3	Active	Cameron Webb	Yung Cheung	15-Feb-17	Monitor	31-Mar-17	1	2	3	3	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9540	In Progress	Develop a Plan for Liquid waste generated from RFR project	1: As per SOW, OPG will be supplying the waste containers for liquid waste. Need to determine which group within OPG is responsible for procuring the drums. 2: OPG waste handling has agreed, based on small volumes of liquid waste expected (3-4 drums), to process liquid waste for the JV. Processing of the liquid waste includes: - Collecting samples and sending it to the appropriate lab for analysis - Any further processing (solidification, filtering), if required - Preparation and submission of RWN to WWMF for acceptance of waste 3: The JV will need to secure a spot within DNGS to hold the liquid waste in drums. This location has not been confirmed.	Jeffrey Palmateer	Kwok Tsang	31-Mar-17	15FEB2017: JV advised that liquid waste will likely be generated towards the end of 2017 (end of moderator drying). The expectation is that there will be 2 to 3 rinses. JV is still in process of developing a list of expected contaminants. 3FEB2017: Action extended for two months for JV to provide more information on the expected contaminants to see if waste can be diverted to active liquid system. New Action item generated from weekly OPG/JV waste meeting held on Friday at 2pm.

Outage Window	Window Description
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
184	184 - RFR-Waste Volume Reduction

Project: Retube and Feeder Replacement - 73105

ONTARIO POWER GENERATION

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14669	Main Heat Transport Header Movement when the MHTS is drained and feeders cut	Event: During Feeder Removal, both disconnect, and subsequent feeder and supports removal, it is possible that the feeder headers may move (rotate or shift). Cause: The Reactor Headers with upper feeders attached, were originally hung from the reactor vault concrete ceiling. The lower feeders were then bolted to end fittings and welded to the upper feeders. The entire assembly was then moved outboard of the reactor by 3" to line up with the MHTS Piping and Steam Generator Piping and the reactor headers were then welded to that piping. When the feeders are disconnected from the end fittings and cut near the headers during RFR, there is a risk that the headers will move to the extent that reconnection and welding of the replacement feeders to the headers will be challenging to impossible without the introduction of welding in spool pieces with additional welds in the piping. The JV has no current plans to restrain the headers prior to feeder disconnect and cutting. Impact: Should the header move, it may be difficult to return the header to it's needed position. The impact of this movement is that it is possible that some of the upper row feeders will have fit-up issues, leading to a push to critical path. JV Risk # 4.122		Active	David Kurpjuweit	Ed Nowakowski	03-Mar-17	Monitor	08-Apr-17	3	2	2	6	2	1	1	2
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			076		076 - Upper Feeder Installation												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Project: Retube and Feeder Replacement - 73106

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14669	Main Heat Transport Header Movement when the MHTS is drained and feeders cut	Event: During Feeder Removal, both disconnect, and subsequent feeder and supports removal, it is possible that the feeder headers may move (rotate or shift). Cause: The Reactor Headers with upper feeders attached, were originally hung from the reactor vault concrete ceiling. The lower feeders were then bolted to end fittings and welded to the upper feeders. The entire assembly was then moved outboard of the reactor by 3" to line up with the MHTS Piping and Steam Generator Piping and the reactor headers were then welded to that piping. When the feeders are disconnected from the end fittings and cut near the headers during RFR, there is a risk that the headers will move to the extent that reconnection and welding of the replacement feeders to the headers will be challenging to impossible without the introduction of welding in spool pieces with additional welds in the piping. The JV has no current plans to restrain the headers prior to feeder disconnect and cutting. Impact: Should the header move, it may be difficult to return the header to it's needed position. The impact of this movement is that it is possible that some of the upper row feeders will have fit-up issues, leading to a push to critical path. JV Risk # 4.122		Active	David Kurpjuweit	Ed Nowakowski	03-Mar-17	Monitor	08-Apr-17	3	2	2	6	2	1	1	2
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			076		076 - Upper Feeder Installation												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Project: Retube and Feeder Replacement - 73111

ONTARIO POWER GENERATION

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14684	Clean Room Construction Delays	Description The Clean Room (which will be located at the DEC) is required to be in service to support Calandria Tube Installation, and Fuel Channel Installation activities. Currently (as of 16Feb2017), the design completion date is scheduled for 17March2017 and the construction schedule has yet to be provided to OPG. Cause Procurement activities on the Clean Room have been delayed due to focus on the other Procurement Packages that were originally required to be delivered as part of the Definition Phase Complete Milestone. Currently, the Clean Room is scheduled to be delivered, and set-up at the DEC by 23JAN2017, however, until the design is completed, the Lead Time associated with manufacturing and delivery is an estimate only, and manufacturing start will not occur until the design is finalized. Currently, there is significant float available in the schedule, as the Clean Room is not required to be in service until late 2017, however, consequences in delays to construction beyond this need date would be very significant. Impact Currently, there is significant float available in the schedule, as the Clean Room is not required to be in service until late 2017, however, consequences of delays to construction beyond this need date would be very significant as CT Preparation (to support CT Installation) and Subassembly Preparation/EF Preparation (to support FC Installation) could not be completed. Day-over-day Critical Path delays would be experienced until the Clean Room could be placed into service.	2	Active	Jeffrey Palmateer	Kevin Hill	16-Feb-17	Monitor	31-Oct-16	4	4	3	16	2	2	2	4
			Outage Window		**Window Description**												
			071		071 - Trial CT Install												
			118		118 - CT Install Series												
			185		185 - RFR-Clean Room CT and FC Preps												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14681	Shortage of Mock-up Components to Support Training Programs	Description In order to support the needs of the Execution Phase of the project, the JV will be required to train a large number of staff on RFR activities. All of these training programs will require some mock-up components, such as Welded Bellows Flange Coupons to support Bellows Cut Training for example. The requirement for mock-up components is expected to be particularly intensive for the CT Install Series, where Operator Qualification requires fabrication of multiple consecutive replacement CT rolled joints that meet leak tightness and geometric criteria. It should be noted that fluctuations in the Project Execution Schedule can also impact mock-up component need dates as Training start dates will have to be tied to the start date for Execution of the work in the field plus appropriate float. Cause In order to complete the Job Performance Measure (JPM) portion of the RFR Training Programs, it is expected that Trainees will be required to operate the RFR Tooling, and complete a varying number of cycles of RFR Series Work Programs on the mock-up. This will require varying quantities of mock-up components to support this work. For CT Install activities, mock-up component demands are expected to be particularly high due to the requirement for each Operator to fabricate multiple replacement CT rolled joints meeting leak tightness criteria. Providing a once rolled, released and conditioned CTSB to facilitate completion of 1 replacement rolled joint will require a CTSB, a CTI, and a CT Spool Piece to fabricate the "original construction" CT rolled joint. Another CTI and CT Spool Piece will be required for the replacement rolled joint. If any of the replacement rolled joints fail to meet either the geometric or leak test requirements, operator qualification would require repeating the qualification program, driving the requirement for even more mock-up components. Impact Unavailability of mock-up components to support training would result in an increase in Proj	3	Active	Jeffrey Palmateer	Kevin Hill	03-Mar-17	Mitigate	01-Dec-18	2	2	1	4	2	1	1	2
			Outage Window		**Window Description**												
			071		071 - Trial CT Install												
			076		076 - Upper Feeder Installation												
			082		082 - RTP Removals, Bridge Replacement												
			083		083 - Lower Feeder Installation												
			098		098 - CTI Release												
			101		101 - Remove FM Bridge and Install RTPs												
			112		112 - PT Sever												
			113		113 - Sever Bellows												
			114		114 - End Fitting Removal												
			115		115 - Pressure Tube Removal												
			116		116 - CTI Removal												
			117		117 - CT Removal												
			118		118 - CT Install Series												
			119		119 - Fuel Channel Install Series												
			920		920 - RFR Series Training												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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14682	Lack of Availability of Mock-ups for Use in Zone 3 Areas (RWPB, and Offsite) with Contaminated Tooling	Description During Execution Phase, there is a high probability that some of the Tooling used for RFR Activities will become contaminated through use. In the event that an issue with a tool is experienced, the tool is contaminated (and cannot be easily decontaminated/has fixed contamination on it), and troubleshooting of the tool is decided to be done off the face, mock-ups will be required in a Zone 3 Contaminated Tooling Workshop (i.e. the RWPB). Additionally, even if a Tool functions as planned during use on Unit 2, it is stated in 509407-0002-00000-30IM-0025 that Tooling will be taken to a Tooling Contaminated Storage Facility, with Level 1 Commissioning prior to use on a subsequent Unit being completed in the RWPB rather than at the DEC. Mock-ups will be required in the RWPB to support complete this Commissioning. It needs to be ensured that an adequate quantity of mock-ups, and space to set-up these mock-ups are provided in the RWPB, and in the Tooling Maintenance Facility. Cause Contaminated Tooling that requires work may be very challenging to release outside the Protected Area to an offsite facility (Tooling Maintenance Facility) to allow appropriate troubleshooting, repairs and testing to be completed. UTPs may require significant remedial actions to be completed to remove contamination before release. These actions may be impractical from a schedule perspective, or may not be successful. Return to Service of Tooling following completion of repairs will often require a mock-up for completion of Testing and Level 1 Commissioning before the Tool is declared "Ready for Service". Additionally, in order to complete Level 1 Commissioning and "Ready for Service" tagging on Tooling being brought back to site for use on Subsequent Units, mock-ups in the RWPB will be required. Impact Generally, in the event of an issue with a Tool during Execution that requires troubleshooting and repairs to be completed off the Reactor Face, spare Tools will be available to	3	Active	Jeffrey Palmateer	Kevin Hill	03-Mar-17	Mitigate	01-Sep-17	2	2	2	4	2	1	1	2

Outage Window	Window Description
071	071 - Trial CT Install
076	076 - Upper Feeder Installation
082	082 - RTP Removals, Bridge Replacement
083	083 - Lower Feeder Installation
098	098 - CTI Release
101	101 - Remove FM Bridge and Install RTPs
112	112 - PT Sever
113	113 - Sever Bellows
114	114 - End Fitting Removal
115	115 - Pressure Tube Removal
116	116 - CTI Removal
117	117 - CT Removal
118	118 - CT Install Series
119	119 - Fuel Channel Install Series
522	522 - Retube Waste Processing Building RWPB
910	910 - RFR Series Tooling
920	920 - RFR Series Training
920	920 - RFR Series Training

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Retube and Feeder Replacement - 73113																	
14260	Vault communications between RPCs and RFR (JV) workers to support RFR Project execution is at Risk	EVENT: There is a risk of lack of vault communications between RPCs and RFR (JV) workers to support RFR Project execution work. CAUSE: A plan for the integration of the Joint Venture's Voice Communication System (VCS) with OPG's RP Audio Visual Teledosimetry System (AVTS) has not been finalized. The RFR Project workers (JV) will be utilizing a JV designed VCS for the RFR Project. The only other work group that can use the JV VCS system is Refurbishment RP so that the RPCs can communicate with the JV workers from within OPG's AVTS system. The benefit is one communication system is used for RFR only. IMPACT: The impact will be the inability of RP Radiation Protection Coordinators (RPC) to communicate with and provide radiation protection for JV workers inside the vault. Additionally, the associated costs to engineer and implement the JV VCS system into the RP AVTS trailer, including required personnel training on the use of the system is approximately $2M. It is expected that the costs for this will be borne from within RP's budget for Refurbishment. RP's RQE did not include the costs of supporting a new AVTS communication system for RFR work. OPG RP will continue to use it's current (tested and proven at both Pickering and Darlington reactor buildings) AVTS communication (wireless headset) system for all other non-RFR project work.	3	Active	Johnathon Hash	Jeff Johansson	22-Feb-17	Monitor	28-Apr-17	4	4	4	16	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			7829	In Progress	Monitor and Perform Oversight on RFR/JV Activities associated with VCS EPC for Radiation Protection Trailer (RPT)	Post-CCB action for RP to monitor and provide oversight on RFR/JV activities associated with the engineering, procurement and construction of VCS (Voice Communication System) for the Radiation Protection Teledosimetry Trailer. CCF1000 was approved by the CCB for funding of the work associated with providing VCS capability in the RPT for the RPCs to communicate with the RFR workers being covered under AVTS. RP needs to follow up with RFR (Kevin Hill, Chris Rambaran of RFR Projects) to obtain a status of the project work associate with VCS. RP, upon obtaining the update, will enter status notes in the "Status Notes" section below, dated and initialed.		Johnathon Hash	Joe Cicchini	31-Mar-17	(1) (June 7, 2016, Johansson): See attachment #1 (email "CCF1000 RP VCS for RFR") from CCB to Finance to disposition to transfer of funding to RFR for the VCS work. (2) (09 Aug; JJ): Initiated contact with RFR SPOCs to obtain a status on the VCS PCD milestones and current progress. Awaiting progress update. (3) (13 Sep; JJ) Have not received any updates from the RFR SPOC to date. Individual has made contact with RP but no update on the subject matter. RP will attempt to follow up again with RFR SPOC to obtain an update. 29DEC2016 JC Whitby HP and JV are working towards the resolution of this. Contact for HP is Matt Lai.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			174		174 - RFR-Pre-reqs Prior to Islanding												
14669	Main Heat Transport Header Movement when the MHTS is drained and feeders cut	Event: During Feeder Removal, both disconnect, and subsequent feeder and supports removal, it is possible that the feeder headers may move (rotate or shift). Cause: The Reactor Headers with upper feeders attached, were originally hung from the reactor vault concrete ceiling. The lower feeders were then bolted to end fittings and welded to the upper feeders. The entire assembly was then moved outboard of the reactor by 3" to line up with the MHTS Piping and Steam Generator Piping and the reactor headers were then welded to that piping. When the feeders are disconnected from the end fittings and cut near the headers during RFR, there is a risk that the headers will move to the extent that reconnection and welding of the replacement feeders to the headers will be challenging to impossible without the introduction of welding in spool pieces with additional welds in the piping. The JV has no current plans to restrain the headers prior to feeder disconnect and cutting. Impact: Should the header move, it may be difficult to return the header to it's needed position. The impact of this movement is that it is possible that some of the upper row feeders will have fit-up issues, leading to a push to critical path. JV Risk # 4.122		Active	David Kurpjuweit	Ed Nowakowski	03-Mar-17	Monitor	08-Apr-17	3	2	2	6	2	1	1	2
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			076		076 - Upper Feeder Installation												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14630	RFR PHT Dry - Potential loss or degradation of NV internals	Execution Event: There is a risk that upon removal of non-return valves (NV), as part of mod package for PHT bulk drying scope of RFR, the internals are damaged or lost and therefore are unavailable to be re-installed at the end of the refurbishment. Current plan is for immediate evaluation of component condition upon removal per protocol established by SDLU and ordering at time of removal if necessary. Cause: Valve internals in bad condition or not able to be stored until re-installation. Impact: New valve internals would need to be purchased, with a lead time of ~ 1 year.	1	Active	Marc Paiment	Steve Fernandes	03-Mar-17	Monitor	30-Apr-17	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14926	[QUARTERLY MONITORING] New Fuel Loading First Execution in ~25 Years- OPG Obligations	Event: Following completion of all Fuel Channel and Feeder Replacement Activities, New Fuel will be manually loaded into all Fuel Channels of the Reactor for the first time at Darlington since new construction (~25 years). The Risk Event is that OPG does not meet its obligation to provide the level of support required to meet the Project Schedule for the New Fuel Load Series, or the proposed New Fuel Loading Sequence is rejected by a Regulatory Authority and the Series Duration is extended. Cause: Extensive interfacing is required with OPG- Fuel Handling and OPG- Security to issue a large volume of New Fuel to the JV in a timely manner to support the production rates required to meet schedule targets. This volume of fuel transfer is significantly larger than that seen during normal operations. In addition, the New Fuel Loading Sequence being followed for Refurbishment will vary from that followed for New Construction (loading of NFBs into a Fuel Channel without immediately installing the Inlet SP and CP) and there is a risk of Regulatory Authority rejection of this sequence. Use of this sequence is a key assumption in the Basis of Estimate for this Series. Impact: Inadequate planning and understanding of Interfaces and Division of Responsibilities between the JV and OPG or rejection of the proposed New Fuel Loading Sequence by a Regulatory Authority could result in an increase of the New Fuel Load Series Duration. This will increase the critical path of the Refurbishment Outage as a whole.	2	Active	Jeffrey Palmateer	Ian Wilcox	02-Mar-17	Mitigate	17-Feb-17	2	1	2	4	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9449	In Progress	FFRB - New Fuel Loading Training Plan to be submitted by JV Training Department to Nuclear Refubishment	New Fuel Loading Training Plan to be submitted by JV Training Department to Nuclear Refurbishment Training Department (Silviu Idita) for review. This Training Plan should define the following: 1. Detail what Training JV Trainers require from OPG (what material/scope, by when, and for how many people). 2. Detail what Training will be delivered by the JV Trainers to all Personnel involved in the New Fuel Load Series. This Training Plan should be delivered before the start of New Fuel Loading Rehearsals.	Ian Wilcox		31-Mar-17	Ian Wilcox- 15DEC: The New Fuel Loading Training Plan has been drafted by the OPG Training Department (Sean Methot) with assistance from Ian Wilcox. The Training Plan is currently with the JV for finalization and sign-off. TCD is 15JAN2017. Following sign-off of the Training Plan, development of any additional course materials by OPG and the JV will begin. Ian Wilcox- 16JAN: The TCD for finalization of the New Fuel Loading Training Plan (15JAN) has been missed. Follow-up with Tom Wigglesworth to take place, and a new TCD will be established. Target was to be no later than 31JAN, however, higher priority JV Work has required pushing this TCD to 31MAR.
9450	In Progress	FFRB - New Fuel Loading Security Requirements	Search direction from Refurbishment Licensing Support Department (David Train) and OPG Safeguards Department (Jai Sanasi), the CNSC and the IAEA on New Fuel Security Requirements as they relate to: - The New Fuel Loading Process (i.e. requirement to secure fuel in channel by immediately installing Inlet Shield Plug and Closure Plug). - IAEA Camera Monitoring (where are cameras required, who sets them up?, can we use VOS or do we need dedicated cameras?). - Security Requirements for the Intermediate Storage Area (do we need a fixed barrier accessed by lock and key). - Do fuel transport runs within the station require Security monitoring? - Does access to the Vault and the 100M RAB need to be restricted to Authorized Personnel? - Does the Fuel Bundle Retrieval Tool need a locked quarantine area?Where/when is Fuel Handling Oversight required?	Ian Wilcox		17-Feb-17	Ian Wilcox (08FEB): No response received as of yet from IAEA, CNSC, or Regulatory Affairs. Follow-ups underway for updated TCD. Pushed TCD to 17FEB2017 for now. Ian Wilcox (18JAN): TCD for IAEA feedback was updated to 31JAN based on direct feedback from CNSC and Regulatory Affairs. Ian Wilcox (15DEC2016): TCD requested for IAEA feedback. Feedback is expected by 31DEC2016. Ian Wilcox (01DEC2016): TCD requested for IAEA feedback. Ian Wilcox(22Nov2016): CNSC has reviewed documentation and requested additional feedback from OPG station personnel. This feedback has been provided to the CNSC. The information will now be socialized with the IAEA. A decision on the NFL security process is pending from the IAEA. WILCOXIA (18NOV): Additional CNSC queries answered. CNSC Review continues. WILCOXIA (02NOV): OPG Regulatory Affairs has been interfacing with the CNSC/IAEA to solicit feedback on whether the New Fuel Load Series Sequence as proposed is acceptable. The Series Leads (Chris Doyle-JV and Ian Wilcox-OPG) have provided Regulatory Affairs with a Process Overview Flowchart as requested by the CNSC. This has been provided to the CNSC, and a response is expected by mid-November.

Outage Window	Window Description
084	084 - Fuel Load

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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Report Owner: L. Greenland
Process Owner: L. Ren
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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15080	risk to HT vac dry (project 73113) timing & duration affected by transmitter blowbacks (RTM project 73425)	1. The full scope of the RTM project 73425/ DSR MS0280-1 transmitter blowbacks is not approved in ROOMS. Several work orders are to be added to scope at the SRB on 16Dec16. Impact: the work is not ready at <T-4 weeks to execution. This applies to all items below as well. Note: several more work orders will be added to scope at a future SRB when the work orders are generated. 2. The work order to fabricate the blowback tool is not in scope. Work order 4995692 is to go to the SRB on 16Dec16. It is not currently known how many tools are to be fabricated. 3. The workplan to perform the blowbacks has not been issued. Refer to NK38-WPL-33000-0597379. An action has been added to the PCC managers list to track the WPL to its issue tcd (29Dec16). 4. The workplans documenting the timing of the blowbacks has not been issued. This WPL is being tracked on the daily WPL conference call. 5. There is a threat that the WPLs will not be assessed and scheduled in time for the start of HT drain (~ 9Jan16). 6. Control mtce and ops resources required to support the blowbacks is TBD. Impact: additional resources may not be available at the time required because the work is not scheduled.. 7. JV eng are determining the impact of the blowbacks on the HT vac dry. HT vac dry may have to stop for the blowbacks. Impact: the window duration may have to be increased.	4	Active	Jeffrey Palmateer	Samad Kasaai	02-Mar-17	Mitigate	01-Apr-17	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			029		029 - HTS Vac Dry												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Retube and Feeder Replacement - 73118																	
14464	RWPB - Increased Risk of Surface/Airborne Contamination Spread inside/outside RWPB	EVENT: There is an increased probability/risk of surface/airborne radioactive contamination spread inside/outside of the RWPB during RWC/DSO filling/lidding activities. CAUSE: The critical activities associated with the high risk is RWC/DSO travels between the lidding station and the hardware station. There is a high potential for presence of loose surface contamination on the RWC/DSO containers from the filling activities (PT, IEF, CTI, AS) and the lidding activities (debris cover removal/installation, RWC and DSO lids removal/installation). The RWC/DSO is expected to exit from the lidding station to the hardware station several times during the process. IMPACT: During these times, surface contamination on the RWC/DSO can become loose and spread across un-controlled areas/barriers causing loss of contamination control in the vicinity, in the building and potentially outside of the building in the unzoned area, and ultimately to the public domain. Without a barrier/structure/enclosure installed within the lidding station and the hardware station corridor to assist with control of contamination, there will be a high potential for work stoppage associated with the WTS activities leading to a backlog of reactor components to be processed. Ultimately, leading to a major impact to RFR critical path work while a makeshift structure/enclosure is designed and installed, or major cleanup of the area inside and potentially outside the RWPB. It is estimated that it might take up to 2 weeks to either design/install a controlled structure/barrier, and to perform decon activities. There is also the risk that the Regulator may demand additional barriers to prevent recurrence and additional analyses to ensure public safety.	3	Active	Johnathon Hash	Scott Stafford	22-Feb-17	Mitigate	01-Aug-17	5	3	4	20	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

14464	RWPB - Increased Risk of Surface/Airborne Contamination Spread inside/outside RWPB	EVENT: There is an increased probability/risk of surface/airborne radioactive contamination spread inside/outside of the RWPB during RWC/DSO filling/lidding activities. CAUSE: The critical activities associated with the high risk is RWC/DSO travels between the lidding station and the hardware station. There is a high potential for presence of loose surface contamination on the RWC/DSO containers from the filling activities (PT, IEF, CTI, AS) and the lidding activities (debris cover removal/installation, RWC and DSO lids removal/installation). The RWC/DSO is expected to exit from the lidding station to the hardware station several times during the process. IMPACT: During these times, surface contamination on the RWC/DSO can become loose and spread across un-controlled areas/barriers causing loss of contamination control in the vicinity, in the building and potentially outside of the building in the unzoned area, and ultimately to the public domain. Without a barrier/structure/enclosure installed within the lidding station and the hardware station corridor to assist with control of contamination, there will be a high potential for work stoppage associated with the WTS activities leading to a backlog of reactor components to be processed. Ultimately, leading to a major impact to RFR critical path work while a makeshift structure/enclosure is designed and installed, or major cleanup of the area inside and potentially outside the RWPB. It is estimated that it might take up to 2 weeks to either design/install a controlled structure/barrier, and to perform decon activities. There is also the risk that the Regulator may demand additional barriers to prevent recurrence and additional analyses to ensure public safety.	**8429**	In Progress	NR-Radiation Protection to monitor JV progress on implementation of an enclosure between lidding and hardware stations in RWPB.	A memo was submitted to the JV from OPG RFR requesting the JV to implement an enclosure between the lidding and hardware stations of the RWPB to ensure proper contamination controls. See Action #8428 for more details and a copy of the memo. As an oversight activity, NR-RP will MONITOR work on the enclosure to ensure that it is progressing according to JV schedule. NR-RP will work closely with OPG RFR to ensure that the work does not get stalled or derailed. This action will be closed once assurance has been granted that the enclosures will be installed on both assembly lines of the waste tooling system. 25AUG2016 - JC - Liette Lemieux, Johnathon Hash and Jeff Johansson are at a walk down/ site tour of ATS. This topic is to be discussed.	Johnathon Hash	Joe Cicchini	30-Jun-17	(10 Aug; JJ). This is a brief summary of the latest oversight activities on the subject enclosure. Trolley access door at the Lidding Station creates a potential of contamination spread when opened. RFR had communicated to the JV that an enclosure is needed to minimize the potential of contamination spread and help facilitate WTS execution, see attached correspondence. The enclosure would extend from the east end of the Lidding Station covering the whole of the Hardware Station, see attached WTS layout. Two independent enclosures would be erected to avoid cross contamination between the two lines. RFR considered the original RPS PermaCon design (see attachment #1 e-mail below) too expensive. RFR would like to explore if the Project can benefit from the tenting experience of the IMS group at Pickering for the proposed enclosure design and had communicated to the JV to start the enclosure design based on a scaffolding concept. RFR had communicated to the JV high level expectations of the enclosure including the need to provide breath air headers at the Hardware Station, see attached e-mail. Currently the JV is in the process of developing a conceptual design; OPG will have the opportunity to review and accept. (Sept 13/2016; JJ) A meeting was held at the ATS facility in Cambridge on Thursday, Aug 25 to review JV RP enclosure concept and confirm elimination of the need for loose contamination survey and decontamination on each exit of DSO from lidding station. The meeting was attended by the JV design team and OPG RFR & RP Teams. Attached below (attachment #2) is the minutes of meeting from the meeting. A working group committee to be established and meet to discuss the requirements for the enclosure and its operational use. An update will be included herein upon issuance of minutes of meeting from the first committee meeting. 15OCT2016 JC - Discussion are in progress as to whether or not a full enclosure, including a roof, will

Outage Window	Window Description
114	114 - End Fitting Removal
522	522 - Retube Waste Processing Building RWPB

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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13991	RWPB - Rework	[Definition Phase] Event: Vendor Rework Cause: Ineffective work practices and/or inefficient work preparation Impact: Potential impact on critical path.		Active	John Hamilton	Adam Coyle	14-Feb-17	Monitor	31-Jul-17	4	2	2	8	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6198	In Progress	Track Rework	Track rework and develop mechanism to minimize construction and engineering rework.	John Hamilton	Adam Coyle	31-Jul-17	12-Jan-16: No rework tracked so far. Will develop mechanism to track rework. Engineering rework is defined as revised design post DEC approval. Construction rework is defined as re-installation or re-fabrication. 29-Jan-16: Rework means that work that is required to correct original work (or rework) that is not defective. To proactively minimize pilecap pour rework, they are now scheduled to the weekends, as any delay at the Sally Port during the weekdays will incur rework to this task. 19-Feb-16: To minimize potential rework/delay, the first pilecap zone pour will use 3 pump trucks, 1 station outside the PA incase one of the other 2 inside the PA fails. 22-Mar-16: Update to Critical Path: Zone 1 pour was executed per logistics plan and executed in 2 hours less than planned. The next 10 pours will be planned and executed in the same manner. 13-Apr-16: Zones 3 and 2 poured within allocated time. No rework. 12-May-16: Zone 4 and 5 poured within allocated time. No rework. 10-Jun-16: Zone 6 and 7 poured within allocated time. No rework. Structural Steel erection has begun with no rework. 15-Jul-16: All pilecap pours completed, structural steel 18% complete. No re-work to date. 08-Aug-16: Structural steel ~50% completed. No re-work to date. 29-Aug-16: Structural steel ~75% completed. Transfer Corridor Caissons 100% completed. No re-work to date. 19-Sep-16: Structural Steel and Transfer Corridor Caissons 100% Completed. South Bunker Wall Pour completed. No re-work to date. 3-Oct-16: No re-work to date. North bunker wall pour scheduled 15-Oct-16. Decking and exterior walls ongoing. 17-Oct-16: No re-work to date. North bunker wall poured 15-Oct-16. Q-Decking completed. Roof and Cladding to begin. 1-Nov-16: No re-work to date. Exterior walls completed. Roofing and Cladding to begin. 14-Nov-16: No re-work to date. Cladding installation ongoing, HVAC ductwork ongoing, crane rail installation on going. 25-Nov-16: No re-work to date. Cladding installati

Outage Window	Window Description
522	522 - Retube Waste Processing Building RWPB

ONTARIO POWER GENERATION

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13980	RWPB Engineering - Delay or Schedule inaccuracy impacting Critical Path	[Definition Phase] Event: delay to Engineering or inaccurate schedule estimate Cause: Inefficient Engineering hand-offs and/or P6 misalignment to need dates Impact: Negative impact to Construction schedule.	3	Active	John Hamilton	Peter Kempton	14-Feb-17	Monitor	31-Aug-17	2	1	3	6	2	1	3	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6199	In Progress	Meet Regular to Identify Delays or Schedule Inaccuracy	Hold regular engineering and construction schedule meetings to identify delay and schedule risks and mitigate as required.	John Hamilton	Peter Kempton	31-Aug-17	12-Jan-16: Meeting held as planned. Report weekly to senior team to ensure full transparency. JV construction/engineering team will be at site to expedite resolution of issues. 01-Feb-16: A 4-week look ahead process is developed for JV to explain weekly the status of all work that is completed as planned, not-completed when it should have been, and the tasks for the next four weeks. Meeting are held weekly on Wednesday with OPG and JV, both construction and engineering teams. 19-Feb-16: Binder Review, Pre-DCAVR/DCAVR dates are tracked daily and discuss weekly with OPG/JV to identify any delays and determine mitigating/recovery actions as required. 22-Mar-16: Engineering is tracking on schedule to the milestone dates. 13-Apr-16: Engineering is tracking on schedule to the milestone dates. 12-May-16: Engineering is still tracking on schedule to the milestone dates. 10-Jun-16: Engineering is still tracking on schedule to the milestone dates. 15-Jul-16: Engineering DCAVRs completed to milestone date. Schedule modifications completed for superstructure installation and has been incorporated into the project schedule with no impact. 08-Aug-16: Meeting still held very frequently (i.e., multiple times per week) to review engineering/construction/procurement schedules. On track to meet superstructure installation milestone date. 29-Aug-16: Meeting still held very frequently (i.e., multiple times per week) to review engineering/construction/procurement schedules. On track to meet superstructure installation milestone date. 19-Sep-16: Meetings held frequently to review engineering/construction/procurement schedules. Superstructure installation milestone met. 3-Oct-16: Meetings still held frequently to review engineering/construction/procurement schedules. 17-Oct-16: Meetings still held frequently to review engineering/construction/procurement schedules. 1-Nov-16: Meetings still held frequently to review engineering/construction/procurement schedules. 14-Nov-

Outage Window	Window Description
522	522 - Retube Waste Processing Building RWPB

ONTARIO POWER GENERATION

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14800	RWPB - Engineering and Vendor Support Documentations not completed in time for CWP development and Commissioning	[Definition Phase] Event: Late submission of JV Engineering or Vendor Support Documentation. Cause: Ineffective coordination between JV Engineering, Construction and Vendors. Impact: Negative Impact on Construction Schedule.		Active	John Hamilton	Peter Kempton	14-Feb-17	Mitigate	31-Jul-17	2	3	1	6	1	2	1	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8993	In Progress	OPG Oversight to work with JV to review CWP Commissioning dates and JV Commissioning Documentation Submissions	OPG Oversight to work with JV to review CWP Commissioning dates and JV Commissioning (i.e. Vendor Submissions) and Engineering (i.e. commissioning specs) submission dates to identify conflicts. (i.e. Commissioning Matrix)	John Hamilton	Peter Kempton	17-Mar-17	30-Aug-2016: OPG Oversight spreadsheet developed identifying all CWP Collaborative Review Dates and JV Engineering submission dates. Issues, Actions, and Owners being tracked during review of spreadsheet with engineering and construction team during weekly meetings. 19-Sep-2016: CWP Collaborative review finalized dates expected 22-Sep-2016 with issues and actions resolve/assigned. 3-Oct-2016: CWP Collaborative review dates provided by coordinators and superintendents. JV Project management reviewing confidence in dates. OPG review to follow. 17-Oct-2016: CWP Collaborative review dates provided and OPG/JV are confident. Engineering Support documentation sheet from JV engineering is outstanding TCD: 21-Oct-16. 31-Oct-16: Engineering Support documentation sheet from JV engineering is outstanding. Deliverable dates need to be provided. Action extended to finalize dates. 14-Nov-16: Engineering Support documentation sheet from JV engineering has outstanding items with required dates. OPG/JV engineering and project management meeting weekly to resolve outstanding issues.25-Nov-16: RWPB Oversight met with JV team and resolved who's responsibilities it is for various deliverables. JV identifying names for the various deliverables relating to commissioning, and will sent the documentation to OPG once completed. 16-Dec-16: Due date moved to February 2016 to align with Commissioning vendor award which will provide final commissioning deliverable dates required in spreadsheet. 13-Jan-17: No update, Commissioning vendor award in February 2016 will provide final commissioning deliverable dates required in spreadsheet. 31-Jan-17: Engineering submission dates only outstanding for commissioning documents. Collaborative reviews ongoing and scheduled inline with engineering deliverables. Meeting scheduled Feb 2, 2017 to review all commissioning documentation requirements. 14-Feb-17: Commissioning manager from JV is now at site. Commissioning manager now has the new Co

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Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14800	RWPB - Engineering and Vendor Support Documentations not completed in time for CWP development and Commissioning	[Definition Phase] Event: Late submission of JV Engineering or Vendor Support Documentation. Cause: Ineffective coordination between JV Engineering, Construction and Vendors. Impact: Negative Impact on Construction Schedule.	10120	In Progress	OPG oversight to work with JV to ensure ITF is updated and closed out as required.	OPG Oversight to work with JV to ensure the following ITF related actions are completed: 1. ITF is split into "Construction" and "Post Construction or Operation" issues. 2. ITF is cleaned up to comply with OPG ITF procedures. 3. All Construction Issues to be resolved prior to 15-May-17.	John Hamilton	Peter Kempton	15-May-17								
			10121	In Progress	OPG Oversight to Ensure JV Completed Engineering Deliverables as per Graded Lette	Engineering Deliverables Spreadsheet as per Graded Letter has been outstanding since September 2016. The attached spreadsheet needs to be completed and have dates provided.	John Hamilton	Peter Kempton	01-Apr-17								
			10122	In Progress	OPG Oversight to identify missing Engineering Deliverables via 4 Week Lookahead	OPG Oversight has created the Construction and Engineering 4 Week Lookaheads, which are reviewed weekly. This document is being used to identify any missing engineering deliverables which are impacting the schedule. Tasks will be flagged weekly and raised to JV Construction and Engineering management for a recovery plan.	John Hamilton	Peter Kempton	31-Jul-17								
			Outage Window		**Window Description**												
			522		522 - Retube Waste Processing Building RWPB												
15121	Procurement of Engineered and Bulk Materials not on Time for Construction	[Definition Phase] Event: Late Delivery of Engineered or Bulk Materials. Cause: Ineffective coordination between JV Construction and JV Engineering. Impact: Negative Impact on Construction Schedule		Active	Peter Kempton	Peter Kempton	14-Feb-17	Mitigate	31-Jul-17	2	3	1	6	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			10118	Draft	OPG oversight to ensure JV provides comprehensive list of all BOMs and confirmation of Delivery Dates	OPG oversight to work with the JV to ensure a comprehensive list of all the latest BOMs (Bill of Materials), showing what has been ordered from these BOMs and the confirmed delivery dates is provided. If there is any equipment or materials that is not on a BOM but is required, the same information will be required. The comprehensive list shall be issued to OPG. OPG has injected "Confirm BOM (FCN if required) Complete/Order Missing Items" as a barrier 2 weeks prior to the Collaborative review of the CWP for all remaining packages. This is a construction tasks to ensure all materials have been provided for construction.	John Hamilton	Peter Kempton	31-Jul-17	14-Feb-17: JV submitted a list of all material being procured at status, to be reviewed by oversight. Initial review suggests the lists may not be completed. The list needs to be aligned with Monday procurement meeting.							
			Outage Window		**Window Description**												
			522		522 - Retube Waste Processing Building RWPB												
12412	RWPB - Retube Waste Processing Building Not Meeting Campus Plan Requirements	[Definition Phase] Event: Retube Waste Processing Building (RWPB) construction activities do not meet the requirements of the Campus Plan Cause: insufficient planning, review and approval of construction strategy Impact: schedule delay and/or additional cost during the Definition Phase.	3	Active	John Hamilton	Adam Coyle	14-Feb-17	Mitigate	30-Jun-17	2	2	2	4	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12412	RWPB - Retube Waste Processing Building Not Meeting Campus Plan Requirements	[Definition Phase] Event: Retube Waste Processing Building (RWPB) construction activities do not meet the requirements of the Campus Plan Cause: insufficient planning, review and approval of construction strategy Impact: schedule delay and/or additional cost during the Definition Phase.	7957	In Progress	Re-evaluate RWPB Flooding Assessment with Final Grading and Flood Mitigating Measures	OPG to re-evaluate RWPB flooding assessment taking into consideration the final RWPB grading and flood mitigating strategy and confirm mitigating impacts to other Darlington Facilities.	John Hamilton	Khai Ngo	30-Jun-17								

17-Jun-16: OPG to re-evaluate RWPB flooding assessment taking into consideration the final RWPB grading and flood mitigating strategy and confirm mitigating impacts to other Darlington Facilities.
15-Jul-16: Re-evaluation currently in progress. Discussions taking place on potentially installing another manhole in the Transfer Corridor to accommodate other Darlington Facilities.
29-Aug-16: Disposition of comments near completion, expected first week of September. New requirements will be tracked. AMEC to put together estimate cost for iterative run of the RWPB flooding assessment so that design team can determine what changes are required/can be incorporated to mitigate potential flood risk.
19-Sep-16: Disposition to comments near completion, expected acceptance this week from remaining stakeholders in Nuclear Safety. New requirements will be tracked. AMEC to put together estimate cost for iterative run of the RWPB flooding assessment so that design team can determine what changes are required/can be incorporated to mitigate potential flood risk.
3-Oct-16: All dispositions resolved. AMEC to issue report.
17-Oct-16: Flooding assessment accepted by OPG Nuclear Safety. AMEC provided 14 recommendations and 4 requirements. All 4 requirements may be resolved via the iterative RWPB flooding assessment. The recommendations and requirements are saved in SharePoint. JV has been provided the flooding report to review and determine what site changes can be incorporated as part of the iterative RWPB flooding assessment. Afterwards, scope to be discussed with AMEC.
1-Nov-16: JV (Ashrf Mohamed) reviewing flooding assessment. JV to meet with OPG (Khai Ngo), tentatively Friday Nov. 4, 2016 to discuss what changes can be incorporated.
14-Nov-16: JV(Ashrf Mohamed) and OPG (Khai Ngo) met on 9-Nov-16 and discussed various options available to further mitigate the impact from flooding. Ashrf to provide drawings to Khai and Khai to define scope for iterative run and inform AME

Outage Window	Window Description
522	522 - Retube Waste Processing Building RWPB

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14983	RWPB - Radiation Monitoring Shielding Installation	[Definition Phase] Event: Late delivery of shielding for RWPB Fixed radiation monitoring equipment. Cause: Ineffective coordination between Engineering, Construction and Vendors to support supply and install of shielding. Impact: Negative Impact on Construction Schedule.		Active	John Hamilton	Kwok Tsang	14-Feb-17	Mitigate	31-Mar-17	3	1	1	3	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9457	In Progress	RWPB Oversight to request weekly updates from JV/CANDU on status of shielding design and expected delivery date of fixed RP equipment.	RWPB Oversight to request weekly updates from JV/CANDU on status of shielding design and expected delivery date of fixed radiation protection equipment shielding.	John Hamilton	Khai Ngo	31-Mar-17	1-Nov-11: Status of shielding report and design will be requested at the next JV/CANDU analysis meeting. RWPB Oversight will also follow up directly with JV lead to obtain status. 14-Nov-16: JV (Ricky Khaloo) is working on report. JV to provide status update on 18-Nov-16. 25-Nov-16: WBM Shielding Report completed by JV and will be sent to OPG for review. 16-Dec-16: JV to internally provide table of all shielding requirements (Candu to JV Civil Design) in December 2016. Report to be formally issued in new year. 13-Jan-17: Report development in progress. OPG/JV determining the feasibilityof moving the WBM by the north west corner to further away from the overhead door. 14-Feb-17: Report with Candu - draft completed and at review stage. WBM has arrived - at Whitby Warehouse.

Outage Window	Window Description
522	522 - Retube Waste Processing Building RWPB

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Shutdown, Layup, Services -																	
14318	Quality Issues [No Window Related]	EVENT: Additional effort needed due to quality issues in design and field work. CAUSE: Human error IMPACT: Additional cost and schedule delay to develop/implement solutions		Active	Andy Ireland		03-Mar-17	Mitigate	31-Oct-19	4	3	4	16	2	3	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5510	In Progress	Initiate Readiness Stakeholder meeting for Breathing Air	Stakeholder meeting to be set at T-5 to ensure Vendor has everything to start execution.	Andy Ireland	Kris Dabiran	31-Dec-16	July 12, 2016-Free Event Challenge Meeting-Civil portion successful. The construction start is scheduled for July 21, 2016. Free Event Challenge Meeting for Mechanical, electrical and I&C will be scheduled for later date. Free Event Challenge Meeting for Mechanical to be scheduled by July 30, 2016. July 28, 2016- Free Event Challenge Meeting-Header portion delayed. Spool prefabrication in the shop behind the schedule, and therefore header construction delayed. One of 3 ITPs for fabrication at Darlington shop approved. 2 with the vendor and approval in progress. August 08, 2016- ITP #2 accepted. ITP # 3 on hold, waiting for ESFOX/WP to issue a FIG and revise the pressure test requirement of FD change paper.
7922	Not Started	Initiate Readiness Stakeholder meeting for Nuclear Dry Air	Stakeholder meeting to be set at T-5 May 1 2017 to ensure Vendor has everything to start execution.	Jos Diening	Greg Gordon	01-May-17	

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14541	SDLU: Low Confidence on Vendor Estimate Based on OPEX [No Window Related]	EVENT: SDLU Projects cost exceeds estimate class at RQE. CAUSE: Scope growth, estimate quality, and productivity issues. IMPACT: Expenditure over allocated contingency		Active	Andy Ireland		15-Jan-17	Mitigate	10-Oct-19	3	3	5	15	2	3	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5510	In Progress	Initiate Readiness Stakeholder meeting for Breathing Air	Stakeholder meeting to be set at T-5 to ensure Vendor has everything to start execution.	Andy Ireland	Kris Dabiran	31-Dec-16	July 12, 2016-Free Event Challenge Meeting-Civil portion successful. The construction start is scheduled for July 21, 2016. Free Event Challenge Meeting for Mechanical, electrical and I&C will be scheduled for later date. Free Event Challenge Meeting for Mechanical to be scheduled by July 30, 2016. July 28, 2016- Free Event Challenge Meeting-Header portion delayed. Spool prefabrication in the shop behind the schedule, and therefore header construction delayed. One of 3 ITPs for fabrication at Darlington shop approved. 2 with the vendor and approval in progress. August 08, 2016- ITP #2 accepted. ITP # 3 on hold, waiting for ESFOX/WP to issue a FIG and revise the pressure test requirement of FD change paper.
7864	Not Started	SDLU to engage resources to perform oversight	1. Biweekly monitoring of vendor. 2. Resident engineer in the field for prompt technical issue resolution. 3. Dedicated cost look-ahead team.	Andy Ireland		10-Oct-19	
7922	Not Started	Initiate Readiness Stakeholder meeting for Nuclear Dry Air	Stakeholder meeting to be set at T-5 May 1 2017 to ensure Vendor has everything to start execution.	Jos Diening	Greg Gordon	01-May-17	

Outage Window	Window Description
000	000 – No Window Related

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14452	Vendor Resource constraints impacting SDLU execution [No Window Related]	EVENT: SDLU project deliverables not completed as planned. CAUSE: Vendor does not have sufficient qualified personnel to complete SDLU project deliverables IMPACT: Delayed project AFS.		Active	Andy Ireland		15-Jan-17	Mitigate	01-Mar-17	3	2	4	12	1	2	4	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7923	In Progress	Oversight on Vendor Performance	Assess the vendor staff performance and proactively request the contractor to take corrective actions where needed Nov 25, 2016 - There are weekly in house project meetings specifically to go over vendor cost performance reports and schedule. See attached meeting notice.	Andy Ireland		31-Jan-17	

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14543	Addition of New / Revised Program Requirements to the SDLU PO Agreement [No Window Related]	EVENT: OPG requires the contractor to implement new and / or revised refurbishment program processes that are not currently in the signed PO agreement. CAUSE: New and / or revised refurbishment processes being implemented that the contractor must adhere to. IMPACT: This could lead to an increase in the PO value. This risk is identified based on recent project OPEX where new requirements for reporting frequency and execution schedule requirements have resulted in Contractor initiated change requests to increase the fixed price portion of the project.		Active	Andy Ireland		15-Jan-17	Accept	31-Jan-17	5	2	1	10	5	2	1	10

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5987	In Progress	Complete PMT review at ES Fox	Initiate and complete a project management review at ES Fox (by consultant)	Andy Ireland		31-Dec-16	PO issued for consultants and review underway. Report expected in spring of 2016.July 8, 2016 - The PMT Review has been completed. New PO from BOP to ES Fox. Alston is on Service Air Oncore approvals. Need to add Oversight findings. 14JUL2016, AI: more time required to adequately address this action.29JUL2016, AI: Service Air / WCA fire fighting has resulted in more time required to address this action appropriately.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13514	Procurement of materials is delayed [No Window Related]	EVENT: Material is ordered/delivered late. CAUSE: Delays in engineering/design/ transit or late release of procurement funds. IMPACT: Delayed Project Schedule and increased costs.		Active	Andy Ireland	Andy Ireland	15-Jan-17	Mitigate	31-Dec-16	3	2	3	9	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7796	In Progress	Perform Oversight to mitigate Risk	Perform Oversight as described by Oversight Activities 181 and 242	Andy Ireland	Kris Dabiran	31-Dec-16	
7952	Not Started	Initiate procurement of NC1 and NC3 Valves	Complete engineering review at a minimum 18 months in advance of restoration window to provide ample lead time for placing purchase order with the vendor	Jos Diening		31-May-18	

Outage Window	Window Description
000	000 – No Window Related

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14576	SDLU Project estimates increase past Class 5 Limit [WIndow 130, 131, 132, 133, 539]	EVENT: SDLU Project estimates for Permanent Equipment Monitoring and Temporary Power Supply increase beyond Class 5 Limit as they are Budgetary estimates. CAUSE: Preliminary Assessing determines additional costs are needed to execute the work IMPACT: Additional cost to project to cover refined estimate.		Active	Andy Ireland		15-Jan-17	Monitor	31-Jan-17	3	3	1	9	3	3	1	9

Outage Window	Window Description
130	130 - LEAD IN Segment PMs & Miscellaneous Work
131	131 - REMOVAL Segment PMs & Miscellaneous Work
132	132 - INSPECT & INSTALL Segment PMs & Misc Work
133	133 - RTS Segment PMs & Miscellaneous Work
539	539 - Temporary Power Distribution System (TPDS)

There are no Draft, Not Started, In Progress Actions associated with the risk.

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14622	Delay to Installation of Unit Power Distribution	EVENT: Delay to installation of Unit Power Distribution project CAUSE: There is a lack of station resources in place to install the breaker. IMPACT: Increased costs to SDLU to pay for premium hours.		Active	Andy Ireland	Jos Diening	15-Jan-17	Monitor	31-Mar-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15043	Refurbishment Breathing Air Support for Bulkhead Installation	EVENT: SDLU project group is preparing EC 136384 as a contingency to allow Refurbishment Breathing Air to be used to install the U2 containment bulkhead. The current refurbishment plan is to use Station Breathing Air for the installation of the Bulkhead. In the case that station breathing air is not available (i.e. D1711 outage moves, or unplanned long forced outage) the contingency plan is to have EC 136384 available to allow refurbishment to become independent from the station needs for bulkhead installation. Use of EC 136384 relies on the Refurbishment Breathing Air System being installed on time. Note that as the defueling campaign moves ahead, there is less of an overlap between the bulkhead installation and D1711. CAUSE: Shutdown Layup has a planned schedule with the Vendor and pulling tasks ahead may not be feasible. In addition, there are delays day-by-day in the field on the breathing air project. There is no room for schedule float as the AFS date is currently February 17, 2017 to support bulkhead installation. IMPACT: Delay to critical path of Refurbishment. Increased costs for more labour work etc.	3	Active	Andy Ireland	Kris Dabiran	15-Jan-17	Accept	29-Jan-17	3	3	3	9	3	3	3	9
			Outage Window		**Window Description**												
			505		505 - Breathing Air - Install and Tie-In (SDL)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13536	Storage of Component Internals [Window 2, 3, 48]	EVENT: Procurement of new parts for replacement is needed. In addition, there is no plan in place to store valve internals which can lead significant quality degradation of the valve internals. CAUSE: 1) Poor/inadequate storage. 2) Poor/Inadequate Layup of parts taken out. 3) Obsolescence of components IMPACT: The delay of finding replacement parts (via ordering of new parts, NICR, etc) may cause additional costs (e.g. replacing degraded components) and schedule delays to refurbishment restart.	4	Active	Andy Ireland	Jos Diening	15-Jan-17	Monitor	31-Jan-17	2	2	4	8	2	2	4	8
			Outage Window		**Window Description**												
			002		002 - Conventional Side Layup												
			048		048 - HTS Aux Drain,Purge,Outside Vault												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13619	SDLU Pre-requisite projects excusable delays [No Window Related]	EVENT: Prerequisite work required before breaker open may be delayed. CAUSE: 1) Poor quality vendor installation planning due to excusable delays.(Some project designs are currently delayed and challenging N-PROC-MA-0022 milestones. These delays are partially caused by OPG inefficiencies in reviews and late scope identification). 2) Productivity lower than planned due to OPG coordination and planning (e.g. permitry, work authorization, RP support). IMPACT: Increased labour costs and additional trades standby costs.		Active	Andy Ireland		15-Jan-17	Mitigate	01-Feb-17	2	4	4	8	1	4	1	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5510	In Progress	Initiate Readiness Stakeholder meeting for Breathing Air	Stakeholder meeting to be set at T-5 to ensure Vendor has everything to start execution.	Andy Ireland	Kris Dabiran	31-Dec-16	July 12, 2016-Free Event Challenge Meeting-Civil portion successful. The construction start is scheduled for July 21, 2016. Free Event Challenge Meeting for Mechanical, electrical and I&C will be scheduled for later date. Free Event Challenge Meeting for Mechanical to be scheduled by July 30, 2016. July 28, 2016- Free Event Challenge Meeting-Header portion delayed. Spool prefabrication in the shop behind the schedule, and therefore header construction delayed. One of 3 ITPs for fabrication at Darlington shop approved. 2 with the vendor and approval in progress. August 08, 2016- ITP #2 accepted. ITP # 3 on hold, waiting for ESFOX/WP to issue a FIG and revise the pressure test requirement of FD change paper.							
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			000		000 – No Window Related												

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14565	Service Air Pipe Routing [Window 506]	EVENT: Lack of space and possibility of encountering rebar in pipe route. CAUSE: Selected pipe route is at heights and certain sections have limited access and/or space. IMPACT: Risk on personal safety and quality during installation.		Active	Andy Ireland	Alston Castelino	15-Jan-17	Mitigate	31-Jan-17	4	1	2	8	3	1	2	6
			Outage Window		**Window Description**												
			506		506 - Service Air - Install and Tie-In (SDL)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11824	Insufficient bulk gases for Refurb work [Window 13, 38]	EVENT: Existing system supply may not have enough bulk gases to do refurbishment work, specifically the gases for SG/Conventional systems layup (Nitrogen and Helium gases). CAUSE: Amount of bulk gases required to fill the systems are unknown. IMPACT: Increased cost and schedule delays to project.		Active	Andy Ireland		15-Jan-17	Accept	30-Apr-17	2	1	3	6	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6752	In Progress	Assess quantity of bulk gases needed (Nitrogen/Helium)	Determine the amount of bulk gases needed for Refurbishment Layup.	Andy Ireland	Alston Castelino	05-May-17	Bulk Nitrogen & Helium Supply will be used for cover gas during draining and layup for the boilers, PHT & Moderator 13May2016: Assumptions used in SRE calculation should be validated. Nitrogen needed for PHT system and Helium for Moderator not taken into account.							
			Outage Window		**Window Description**												
			013		013 - PHT Bulk Drain (Includes V42 Mod)												
			038		038 - Moderator Drained & Flush												
13432	New 600 lb flanges not installed in Unit 2 BO1/2 [Window 3]	EVENT: New 600 lb flanges will not be installed prior to installation of the wet layup skids during U2 refurbishment on BO1/BO2. CAUSE: Based on OPEX from previous outages, WOs 2391690 and 32391692 were constantly pushed from outage to outage. IMPACT: Will impact Costs, schedule of DNRU2 if not implemented prior to outage.		Active	Andy Ireland	Alston Castelino	15-Jan-17	Mitigate	30-Oct-16	3	2	2	6	3	1	1	3
			Outage Window		**Window Description**												
			003		003 - Secondary Side SG Layup												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13608	No PMT Cost Reduction [No Window Related]	EVENT: Vendor PMT costs do not reduce if vendor workload is decreased. CAUSE: ESFox has stated that it needs to maintain PMT resources across all SDLU/RSF projects.IMPACT: PMT costs may be increased per project as the overhead for the entire team is to be maintained upon project cancellation		Active	Andy Ireland		15-Jan-17	Monitor	31-Jan-17	3	2	1	6	3	2	1	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5987	In Progress	Complete PMT review at ES Fox	Initiate and complete a project management review at ES Fox (by consultant)	Andy Ireland		31-Dec-16	PO issued for consultants and review underway. Report expected in spring of 2016.July 8, 2016 - The PMT Review has been completed. New PO from BOP to ES Fox. Alston is on Service Air Oncore approvals. Need to add Oversight findings. 14JUL2016, AI: more time required to adequately address this action.29JUL2016, AI: Service Air / WCA fire fighting has resulted in more time required to address this action appropriately.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14045	Insufficient Breathing Air for Power Track work during Refurbishment [Window 505]	EVENT: Breathing Air distribution and capacity assessment concludes that there is insufficient Breathing Air to support Refurbishment activities in the Fuelling Machine Duct CAUSE: Refurbishment requirements of 24 workers in plastic suits exceeds the maximum number of workers that have ever worked in the Fuelling Machine Duct (based on OPEX). IMPACT: Additional cost to the project to create a new modification to support this work. Delay to SDLU Breathing Air schedule		Active	Andy Ireland	Kris Dabiran	15-Jan-17	Mitigate	03-Jul-17	2	2	3	6	1	1	1	1
			Outage Window		**Window Description**												
			505		505 - Breathing Air - Install and Tie-In (SDL)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14420	Wet Layup Skids not Meeting Intended Design Function [Window 37]	EVENT: Wet layup skids may not meet intended design function CAUSE: Procurement/fabrication of skids does not meet the required specifications IMPACT: Delay to project schedule and increase in project costs		Active	Andy Ireland	Jos Diening	15-Jan-17	Monitor	30-Aug-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			003		003 - Secondary Side SG Layup												

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14420	Wet Layup Skids not Meeting Intended Design Function [Window 37]	EVENT: Wet layup skids may not meet intended design function CAUSE: Procurement/fabrication of skids does not meet the required specifications IMPACT: Delay to project schedule and i	037		037 - Sec Side SG Clean & Install Access Ports												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14421	Inflatable Bung does not provide Adequate Sealing [Window 37]	EVENT: Inflatable bung may not provide adequate sealing of nitrogen blanket CAUSE: Issues in bung design or bung fabrication IMPACT: Transfer of nitrogen beyond the intended system barriers leading to a delay in the T/G refurbishment schedule. Minimal impact to cost. Schedule delay to project.		Active	Andy Ireland	Jos Diening	15-Jan-17	Mitigate	17-Mar-17	2	1	3	6	1	1	2	2
			Outage Window		**Window Description**												
			037		037 - Sec Side SG Clean & Install Access Ports												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14451	Refurbishment Compressors AFS to support Bulkhead Tie-in [Window 505]	EVENT: Breathing Air Pre Bulkhead Tie-in (MEC #135592) not installed in time. Assuming that the breathing air refurbishment compressors will be available to support bulkhead tie-in. (ECR# 24553) CAUSE: Compressor AFS date does not give float time to install Bulkhead tie-in before January 2017. There is little room for schedule slippage as the AFS date for the compressors is to be January 17, 2017 and installation of the bulkhead begins in February 2017. IMPACT: Delay to critical path of Refurbishment. Increased costs to expedite procurement/installation of compressors.	3	Active	Andy Ireland	Kris Dabiran	15-Jan-17	Mitigate	31-Jan-17	3	2	2	6	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7796	In Progress	Perform Oversight to mitigate Risk	Perform Oversight as described by Oversight Activities 181 and 242	Andy Ireland	Kris Dabiran	31-Dec-16								
			Outage Window		**Window Description**												
			505		505 - Breathing Air - Install and Tie-In (SDL)												
14566	LPSW Drain Tie-in (Service Air) [Window 506]	EVENT: LPSW line integrity is poor. CAUSE: There is high corrosion and low wall thickness at planned hot tap location. IMPACT: Schedule delays and higher cost to execute planned hot tap.		Active	Andy Ireland		15-Jan-17	Mitigate	31-Jan-17	3	1	2	6	3	1	1	3
			Outage Window		**Window Description**												
			506		506 - Service Air - Install and Tie-In (SDL)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11361	Degraded condition of PHT IX columns may affect layup strategies [Window 13]	EVENT: High pressure differential across IX columns.Degraded conditions of the PHT IX columns. CAUSE: Degraded conditions of the PHT IX columns. IMPACT: Might affect unit startup schedule by prolonging purification	2	Active	Andy Ireland		15-Jan-17	Monitor	31-Oct-16	2	2	2	4	2	2	2	4
			Outage Window		**Window Description**												
			013		013 - PHT Bulk Drain (Includes V42 Mod)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12012	Station configuration does not support layup alignment (Layup/Services) [No Window Related]	EVENT: Station configuration does not support layup alignment. CAUSE: 1) MP"K" and "F" work not completed, or if there is work required to support layup has not been identified yet (not known because system will be in non-standard operation). 2) Field configurations different than planned and discovery issues requiring design field changes. For example, Dry Air purge component alignment IMPACT: Results in additional costs and schedule delays.	2	Active	Andy Ireland		15-Jan-17	Monitor	15-Oct-16	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13462	SGECS N2 blanketing design (MEC 123794) [Window 3]	EVENT: Layup of SGECS for U3/U1/U4 will be delayed due to unavailbility of Nitrogen. CAUSE: Current design for Unit 2 SG secondary side layup uses nitrogen supply from the existing SGECS but the configuration of U3/U1/U4 are not the same - they use air. Currently no EPC contract for U3/1/4 nitrogen supply. IMPACT: Increased cost and schedule delay to project.		Active	Andy Ireland		15-Jan-17	Mitigate	31-Jan-17	2	2	1	4	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5329	In Progress	SG Layup redesign for U3/U1/U4	A redesign for the layup of the top of the SG for U3/U1/U4 has to be made. Design will be initiated after U2 refurbishment starts. This will allow for evaluating effectiveness of Unit 2 design and use OPEX for Unit 1, 3, and 4 Nitrogen Blanketing design.	Andy Ireland	Alston Castelino	24-Feb-17	28Jan2016: ECR 24399 approved. 29Oct2015: Needs Doc signed. ECR to be initiated. 15Oct2015: Needs Doc drafted and routed for review/signatures. 28July2015: SDLU Project to create ECR for approval. 05Dec2016: Re-design for U1/U3/U4 will be determined based on effectiveness for N2 blanketing modification for U2							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13462	SGECS N2 blanketing design (MEC 123794) [Window 3]	EVENT: Layup of SGECS for U3/U1/U4 will be delayed due to unavailbility of Nitrogen. CAUSE: Current design for Unit 2 SG secondary side layup uses nitrogen supply from the existing SGE	**Outage Window**		**Window Description**												
			003		003 - Secondary Side SG Layup												
13593	CCW may need to be laid up [Window 57]	EVENT: CCW system may need to be laid up (Contingent cost to be allocated for this project). CAUSE: If LPSW outage lasts more than 60 days. IMPACT: Schedule delays, increased scope and costs		Active	Andy Ireland		15-Jan-17	Monitor	03-Nov-17	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			057		057 - LPSW Outage Phase 2 & 3												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13848	Requirements for monitoring of permanent station system components and equipment are not optimized [No Window Related]	EVENT: The contractor's resource strategy for completing scope associated with monitoring of permanent station system components and equipment is not optimized. CAUSE: Uncertainties associated with the scope IMPACT: Increased project cost to execute scope.	4	Active	Andy Ireland	Andy Ireland	15-Jan-17	Mitigate	15-Sep-16	4	1	1	4	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14360	Contractors Field Staff Not Prepared To Perform Field Work [No Window Related]	EVENT: Contractor field staff are not prepared (knowledge, experience) to perform field work CAUSE: Contractor field staff lack required qualifications RESULT: Delay to the execution schedule		Active	Andy Ireland	Andy Ireland	15-Jan-17	Mitigate	15-Oct-16	2	1	2	4	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6810	Not Started	Obtain Vendor employee training matrix	Review Vendor employee training matrix to ensure field staff are qualified	Andy Ireland	Andy Ireland	15-Oct-16								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
14361	Contractor Field Staff Impact Station Operations [No Window Related]	EVENT: Contractor field staff negatively impact station operations CAUSE: Lack of contractor awareness of impact to station operations during field execution IMPACT: Delay to the station schedule		Active	Andy Ireland	Andy Ireland	15-Jan-17	Mitigate	15-Oct-16	2	1	2	4	1	1	2	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14580	Additional minor mods may be required to support the Dry Air Conventional Scope of Work [Window 2]	EVENT: Additional minor mods may be required to support the Dry Air Conventional Scope of Work. CAUSE: Constructability team uncovering new needs as assessing progressesIMPACT: Result in increase in scope, schedule and cost	2	Active	Jos Diening	Wayne Allen	15-Jan-17	Monitor	31-May-19	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			002		002 - Conventional Side Layup												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13509	Dose rates higher than planned [No Window Related]	EVENT: Actual dose is higher than planned. CAUSE: This can be caused by higher fields in the vault. IMPACT: Delays to schedule, associated costs, and increased dose to workers and/or increased personnel required.		Active	Andy Ireland	Andy Ireland	15-Jan-17	Accept	31-Dec-16	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13636	Currently no alternate cooling water design for SA compressors [Window 506]	EVENT: No cooling water available during 60 day LPSW outage. CAUSE: No alternate connection designed in SA mod or LPSW alternate cooling mod, to LPSW. IMPACT: More design work required on existing mods (T/P mod) or reduced service air capacity.		Active	Andy Ireland		15-Jan-17	Accept	01-Nov-17	2	1	1	2	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

13636	Currently no alternate cooling water design for SA compressors [Window 506]	EVENT: No cooling water available during 60 day LPSW outage. CAUSE: No alternate connection designed in SA mod or LPSW alternate cooling mod, to LPSW. IMPACT: More design work required on existing mods (T/P mod) or reduced service air capacity.								5Feb2016: For U3 outage, provisions available to supply temporary power/cooling water to SA compressor. Impact on U3 will be determined by begining of U3 outage. 15 July 2016-Kris Dabiran-ENA Holds below assigned to NR Design Engineering: WO Task ENA Hold Description Need Date Department Crew 04931745 01 DURING U1 LPSW OUTAGE, TEMPORARY WATER SUPPLY TO 0-75130-CP12 WILL BE REQUIRED TO SUPPORT CONTINUED BREATHING AIR SUPPLY TO CONTAINMENT Sept. 15.16 NRDEM NRDD 04931746 01 DURING U2 LPSW OUTAGE, TEMPORARY WATER SUPPLY TO 0-75130-CP14 WILL BE REQUIRED TO SUPPORT CONTINUED BREATHING AIR SUPPLY TO CONTAINMENT Sept. 15.16 NRDEM NRDD 04931747 01 DURING U4 LPSW OUTAGE, TEMPORARY WATER SUPPLY TO 0-75130-CP16 WILL BE REQUIRED TO SUPPORT CONTINUED BREATHING AIR SUPPLY TO CONTAINMENT Sept. 15.16

			5476	In Progress	Investigate impact of no alternate cooling water for SA compressors during U3 LPSW outage	SDLU to investigate the the impact of having no alternate cooling water to Service Air Compressors during the U3 LPSW outage.	Andy Ireland	Alston Castelino	28-Apr-17	NRDEM NRDD 04931748 01 BREATHING AIR COMPRESSOR MOTOR BREAKERS WILL BE SUPPLIED FROM 4-53340-28CB11 (0-75130-CP16). IN CASE OF BUS 28 OUTAGE, THE POWER TO THE COMPRESSOR MUST BE SUPPLIED FROM OTHER SOURCES. Sept. 15.16 NRDEM NRLD 04931749 01 BREATHING AIR COMPRESSOR MOTOR BREAKERS WILL BE SUPPLIED FROM 2-53340-28CB11 (0-75130-CP14). IN CASE OF BUS 28 OUTAGE, THE POWER TO THE COMPRESSOR MUST BE SUPPLIED FROM OTHER SOURCES. Sept. 15.16 NRDEM NRLD 04931883 01 BREATHING AIR COMPRESSOR MOTOR BREAKERS WILL BE SUPPLIED FROM 1-53340-28CB11 (0-75130-CP12). IN CASE OF BUS 28 OUTAGE, THE POWER TO THE COMPRESSOR MUST BE SUPPLIED FROM OTHER SOURCES. Sept. 15.16 NRDEM NRLD 04931888 01 INSTALL/REMOVE TEMPORARY WATER AND POWER SUPPLIES TO 0-75110-CP13 DURING U3 BU27 AND/OR LPSW OUTAGE Sept. 15.16 NRDEM NRGD

																					04931891 01 INSTALL/REMOVE TEMPORARY LPSW AND/OR POWER TO 0-75110-CP12 DURING U3 BU28 OR LPSW OUTAGE Sept. 15.16 NRDEM NRGD 04931892 01 INSTALL/REMOVE TEMPORARY WATER AND ELECTRICAL SUPPLY TO 0-75110-
			5477	Draft	Operations to revise OM	Operations to revise Operating Manual to turn off CP11 during U2 outage.															
			Outage Window		**Window Description**																
			506		506 - Service Air - Install and Tie-In (SDL)																
14129	OPG Acceptance of Design ECs without having Final Certified Vendor (Atlas Copco) Documents [Window 505]	EVENT: Rework might be needed for Design EC to allign with final approved Atlas Copco documents. CAUSE: Accepting the Design ECs without verifying information from Approved Atlas Copco Documents. IMPACT: Additional cost and schedule delay for rework.		Active	Andy Ireland	Kris Dabiran	15-Jan-17	Mitigate	30-Aug-16	1	1	2	2	1	1	1	1				
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**											
			7272	In Progress	Monitor Receipt of Atlas Copco Documentation	Refer to NK38-CORR-09701-0579150. Breathing Air Design for Header was accepted without all of vendor documentation provided. OPG MTL to track receipt of documents from vendor to DSP and ensure that documents are reviewed against design to ensure that no changes are required. Update this action as required until all documents in NK38-CORR-09701-0579150 are received all changes to EC are identified.	Andy Ireland	Kris Dabiran	10-Jan-17	It is in progress. More document received from Atlas Copco, but it is not completed yet. Discussed with ESFOX PM in Project meeting, 14 July 2016 and he will make a conference call to follow up on Friday July 15, 16. August 08, 16-Kris Dabiran- FMEA (failure mode analysis issued by Atlas Copco on August 08, 16, reviewed and accepted by WP (DSP) and issued to OPG. Still waiting and follow up for all the documentations to be issued September 22,16-Kris Dabiran- ESFOX informed SDLU in the project meeting, that documentation from one of the compressor component supplier delayed and affect CSA requirement in progress in Atlas Copco Montreal office. Dec. 05, 2016-KrisDabiran- ESFOX re-base lining the P6 schedule and Post DCAVR activities (including verification of I & C supplier documentation) is due 04-Jan-17. Action is then extended to Jan. 10, 2016.				
			Outage Window		**Window Description**																
			505		505 - Breathing Air - Install and Tie-In (SDL)																
14323	Breathing Air Additional Scope Increase [Window 505]	EVENT: Design of TMOD for Breathing Air Tie-in (for bulkhead installation) is delayed. ECR 24637 has been initiated to use the refurbishment breathing air system to install the refurbishment containment bulkhead. CAUSE: Scope was not identified in the Scope of Work or the MDR and thus was identified late in the design IMPACT: Additional cost to expedite design and field work.	4	Active	Andy Ireland	Kris Dabiran	15-Jan-17	Mitigate	01-Dec-16	1	2	1	2	1	1	1	1				
			Outage Window		**Window Description**																
			505		505 - Breathing Air - Install and Tie-In (SDL)																
			There are no Draft, Not Started, In Progress Actions associated with the risk.																		

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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Report Owner: L. Greenland
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Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14563	Breathing Air/Service Air Compressors Maintenance [Window 57, 505, 506]	EVENT: Human performance issue for operations & maintenance personnel CAUSE: New compressors may not meet intended design function. IMPACT: Delay in schedule due to insufficient knowledge of the new compressors by operations & maintenance personnel.		Active	Andy Ireland		15-Jan-17	Monitor	16-Oct-19	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			057		057 - LPSW Outage Phase 2 & 3												
			505		505 - Breathing Air - Install and Tie-In (SDL)												
			506		506 - Service Air - Install and Tie-In (SDL)												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14624	New Breakers Interface with Obsolete MCC	EVENT: New breakers will not interface with older obsolete MCC. CAUSE: MCC is too old causing interface problems with the new equipment. IMPACT: Delay in schedule to solve the interface problems.		Active	Andy Ireland	Jos Diening	15-Jan-17	Mitigate	17-Oct-16	1	1	2	2	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12022	Additional minor mods may be required to support the SGECS Scope of Work [Window 3]	EVENT: Additional minor mods may be required to support the SGECS Scope of Work. CAUSE: Constructability team uncovering new needs as assessing progresses. IMPACT: Result in increase in scope, schedule and cost	2	Active	Andy Ireland	Alston Castelino	15-Jan-17	Monitor	31-May-19	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			003		003 - Secondary Side SG Layup												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13588	Discovery work [No Window Related]	EVENT: There is a risk that there will be work that is not accounted for. Funding might not be allocated to something that is unplanned. CAUSE: Unforeseeable events such as a broken component in the field. For example, SG internal condition is different than expected. IMPACT: Addition of work during next phase which will increase cost and schedule delays.		Active	Andy Ireland		15-Jan-17	Accept	31-Oct-19	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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Project: Specialized Projects - 73310																	
11982	Delay In Contracting Process Impacting SDS Project Schedule [Window 7]	Event: Delay in material availability. Cause: Delay in SDS procurement contract issuance results in a delay of material availability for installation. Impact: Cost and schedule of the project would be impacted if materials were unavailable on time.	4	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Mitigate	31-Dec-17	2	1	4	8	2	1	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2713	In Progress	Expedite new contract process	Hold regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts until all Project contracts have been issued.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts. As a result, a number of contracts have been issued. This level of oversight will continue as required. All the other contracts, including service and cables (regarding to 3220) We may still need to exercise and expedite hiring of resources for installation - 31-Jun-2017

Outage Window	Window Description
007	007 - SDS1 & SDS2 Mods & Rehab

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
12323	Hardware Delivery Delay Impacting SDS Software Integration [Work Window 7]	Event: Hardware delivery is late reducing the time available to integrate hardware components with avilable software. Cause: The late issuance of hardware contracts squeezes the equipment supplliers reducing their available float and their ability to handle unexpected changes. Impact: This risk would cause a significant schedule impact which would in turn impact cost.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	31-Dec-17	2	1	3	6	2	1	3	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2713	In Progress	Expedite new contract process	Hold regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts until all Project contracts have been issued.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts. As a result, a number of contracts have been issued. This level of oversight will continue as required. All the other contracts, including service and cables (regarding to 3220) We may still need to exercise and expedite hiring of resources for installation - 31-Jun-2017

Outage Window	Window Description
007	007 - SDS1 & SDS2 Mods & Rehab

ONTARIO POWER GENERATION

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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13463	SDS Interface Compatibility Issues Discovered During Installation [Window 7]	Event: SDS computer compatibility issues during installation. Cause: The system will be thoroughly tested prior to installation under simulated conditions but some conditions (Ispecifically driving actual field solenoid valves) cannot be simulated and therefore must be tested in the field. Impact: Both cost and schedule would be impacted by the interface compatibility issues if they arise.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Accept	30-Jun-18	2	1	3	6	1	1	3	3
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12327	SDS Computer Project Failure to Meet Hardware Design Requirements [Window 7]	Event: The system as designed fails to meet design requirements during design testing and qualification. Cause: Latent design flaws. Impact: Both cost and schedule could be impacted due to substantial rework being required.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	31-Dec-17	1	1	4	4	1	1	4	4
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14511	SDS Computer Qualified Resources Unavailable During Execution [Window 5,7,12]	EVENT: Delay due to a reassignment of SDS execution resources CAUSE: The resources currently assigned per the current SDS execution resourcing strategy are unavailable, requiring the contracting of resources less familiar with the site, system and scope of work and resulting in a delay to the schedule. IMPACT: Schedule is pushed resulting in a cost impact to the project because the work cannot be completed as planned.		Active	Ivan Dimitrov	Dale Schnedler	02-Mar-17	Mitigate	31-Dec-17	1	1	4	4	1	1	4	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7761	In Progress	SDS Computers Resourcing Follow Up	Follow up with Darlington Projects and Control Maintenance to ensure that SDS qualified resources are available to support installation of the replacement SDS Computers. Develop and document a resource strategy for execution.	Ivan Dimitrov	P Sharawy	30-Jul-17	Work in this area has progressed as follows. · Breakdown of BTU and PWU installation effort provided and approved in accordance with CPAA in October, 2016. · Follow up meeting with Darlington Projects and Control Maintenance (Refurbishment) to review scope, effort and resource requirements in October, 2016. · Follow up meeting with Control Maintenance Darlington to review scope, effort and resource needs in December, 2016. · There is still a risk that sufficient SDS qualified resources would not be available to support installation. Need to confirm availability closer to installation							
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
12328	SDS Computer Project Grounding Problem [Window 7]	Event: SDS Computer grounding discovered during install. Cause: Grounding has been an issue in past computer system installations therefore there is a risk tha the same issue will arise with the installation of the new equipment. Impact: Both cost and schedule ofthe project would be impacted.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	30-Jun-18	1	1	3	3	1	1	3	3
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13464	SDS Equipment Fails During Installation [Window 7]	Event: SDS Equipment fails during or before installation. Cause: All SDS computer components are being prcured at the same time therefore, by the time the parts are installed for U4 refrubishmnet they will have been in storage for 7 years creating a risk that they will fail when installed. Impact: The failure of the equipment will have an impact on both cost and schedule as replacement components will have to be procured and installed.	2	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Mitigate	30-Jun-18	1	1	3	3	1	1	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5194	In Progress	Spare part purchases for vulnerable components	Confirm and order spares for vulnerable components.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Spares must be ordered before AFS - 3-Jun-2017							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13464	SDS Equipment Fails During Installation [Window 7]	Event: SDS Equipment fails during or before installation. Cause: All SDS computer components are being prcured at the same time therefore, by the time the parts are installed for U4 refrubi	**Outage Window**		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Steam Generators -																	
13448	PSC Execution Window Extended as a Result of Integrating Schedule with Other Work Groups	EVENT: Baseline execution window for primary side clean work impacted and extended. CAUSE: Schedule integration between multiple work groups performing work during the SG primary side window, including IMS and other projects. IMPACT: This will impact SG critical path and result in additional costs to the project.	3	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Accept	02-Jul-18	5	2	4	20	5	2	4	20
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9198	In Progress	Process PCD 16 to address the integration of Window 62	Review of PCD 16 is underway.		Pejman Asgaripour	Mike Lutz	01-Apr-17							
			Outage Window	**Window Description**													
			062	062 - Primary Side SG Clean and Inspect													
13450	SG Primary Side Demobilization Activities Extended Due to Layup and Inspection Schedule	EVENT: EPC vendor will need to carry resources (trades and PMT) for an extended duration in order to support SG demobilization activities at the end of the SG primary side maintenance window while IMS is executing work. CAUSE: Changes to the overall refurbishment schedule that are not driven by the EPC contractor. IMPACT: This could result in an extension to the baseline schedule and a significant cost increase to the project.	3	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Accept	02-Jul-18	5	2	4	20	5	2	4	20
			Outage Window	**Window Description**													
			062	062 - Primary Side SG Clean and Inspect													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14709	Steam Generator New Manway Manipulator's Not Procured In Time For Start of Layup	EVENT: Steam Generator new manway manipulator's are not procured in time for start of layup [Window 34] CAUSE: Delays to design and/or procurement of new manipulators IMPACT: Delays in executing the SG primary side layup activities	3	Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Accept	28-Apr-17	5	1	3	15	5	1	3	15
			Outage Window	**Window Description**													
			034	034 - Primary Side SG Layup													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13415	Site services/support unavailable	EVENT: Field services like electrical connections, water connections, layout areas, service air, breathing air, station provided PPEs, permitry, scaffolding area, and/or rad protection may not be available when required by the schedule. CAUSE: Two groups assigned to the same resource at the same time. Priority being given to other project groups to use services identified by the SG project. IMPACT: Delays to project schedule and/or increased costs.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	15-Dec-18	3	2	4	12	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			1893	In Progress	Confirm NR services has provided connection pt and adequate contaminated exhaust capacity for SG project.	Confirm NR services has provided connection pt and adequate contaminated exhaust capacity for SG project. Sources of contaminated exhaust for the SG project are SG Primary Side Layup, primary side clean, and bleed cooler inspection.		Pejman Asgaripour	Mike Lutz	24-Mar-17	Feb 23, 2017 - Site infrastructure plan submission delayed. TCD for OPG review is March 7. OPG Acceptance Planned for March 17. Jan 27, 2017 - Site infrastructure plan TCD revised based on Vendor forecast. Dec 16, 2016 - Site Infrastructure Plan is not finalized, information cannot be routed to SRE. TCD revised. Nov 3, 2016 - Site Infrastructure Plan to be finalize dby the end of November. Communicate Contaminated exhaust requirements to SRE Dec 15/16 Aug. 16/16: Connection points for contaminated exhaust are identified in the vendor's site infrastructure plan for PSC and in the work plan for bleed cooler. Since the windows for both of these projects are under review it is not possible to properly perform an capacity review at this time. Due date moved to November 2016. July 18/16: Due date moved due to customer validation testing. On going discussion with all stakeholders. Action will be completed after schedule integration.			

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13415	Site services/support unavailable	EVENT: Field services like electrical connections, water connections, layout areas, service air, breathing air, station provided PPEs, permitry, scaffolding area, and/or rad protection may not be available when required by the schedule. CAUSE: Two groups assigned to the same resource at the same time. Priority being given to other project groups to use services identified by the SG project. IMPACT: Delays to project schedule and/or increased costs.	7016	In Progress	Steam Generators - Provide Site Requirements to Refurbishment SPOCS	Provide finalized site requirements from the Site Infrastructure Plan to Refurb SPOCS.	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17									Dec. 16/16: Action dependant on the site infrastructure plan being updated which has been delayed due to changes to the CWPs. Due date revised. Oct 24/16: Due Date Updated. August 26, 2016: Due date moved due to pending changes to the execution dates for both the primary and secondary side windows (windows 037 and 062). July 18/16: Due date moved due to customer validation testing. May 24/16: Draft requirements have been provided to all SPOCs previously. This action is to provide the finalized requirements based on walkdown results and the CWP process. Site Infrastructure plan is scheduled to be finalized on June 10/16.
			9194	In Progress	Steam Generators - Summarization of Services in the Site Infrastructure Plan	Summarizing the services required from the vendors given in the Site Infrastructure Plan. Services includes, but are not limited to: -Electrical -Service Air -Breathing Air -Water -Decontamination Services -Active Ventilation -Drains -Radiation Protection Services -Communication Requirements	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17									Nov 3/16: Due Date Updated. Oct 5/16: Action created.
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			037		037 - Sec Side SG Clean & Install Access Ports												
			062		062 - Primary Side SG Clean and Inspect												
			105		105 - Vault Projects After Feeder Removal												
13581	Materials procured and fabricated to support SG project do not meet contractual requirements	EVENT: Materials procured and/or fabricated by the EPC vendor does not satisfy the requirements outlined in the contract agreement and purchase order. CAUSE: Potential causes include: counterfit or fraudulent materials, late or wrong materials, materials without sufficient quality documentation, non-adherence to technical specifications, errors implementing revisions to specifications, sub-contractor issues IMPACT: Delays and rework in procurement activities which could result in increases to the execution cost and schedule delays.	3	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Monitor	14-Dec-18	2	1	5	10	2	1	5	10
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			037		037 - Sec Side SG Clean & Install Access Ports												
			062		062 - Primary Side SG Clean and Inspect												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13824	Addition of New / Revised Program Requirements to the SG EPC Agreement	EVENT: OPG requires the contractor to implement new and / or revised refurbishment program processes that are not currently in the signed EPC agreement. CAUSE: New and / or revised refurbishment processes being implemented that the contractor must adhere to. IMPACT: This could lead to an increase in the EPC fixed contract price. This risk is identified based on recent project OPEX where new requirements for reporting frequency and execution schedule requirements have resulted in Contractor initiated change requests to increase the fixed price portion of the project.		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Accept	15-Dec-18	5	2	1	10	5	2	2	10
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13824	Addition of New / Revised Program Requirements to the SG EPC Agreement	EVENT: OPG requires the contractor to implement new and / or revised refurbishment program processes that are not currently in the signed EPC agreement. CAUSE: New and / or revised refurbishment processes being implemented that the contractor must adhere to. IMPACT: This could lead to an increase in the EPC fixed contract price. This risk is identified based on recent project OPEX where new requirements for reporting frequency and execution schedule requirements have resulted in Contractor initiated change requests to increase the fixed price portion of the project.	6143	In Progress	Review New / Revised OPG Governance for Impact to SG Agreement	Review new / revised OPG governance that the refurbishment program requires the contractor to adhere in order to determine the impact to the SG agreement. Project change directives may be required for changes that impact the overall contract schedule and / or price.	Pejman Asgaripour	Rex Harvey	15-Feb-17								

Oct 24/16: Due date updated.
August 23, 2016: OPG provided feedback on Contract Implications to the NR Execution Expectations on August 3, 2016, with vendor response requested August 17, 2016. Still awaiting vendor feedback. TCD update.
June 29, 2016: Vendor has reviewed NR Execution Expectations #1-15 and assessed for impact to contract. Ongoing discussions between vendor, project team and Contract Management to to assess and understand impact and resolve per the terms and conditions of the agreement.
Dec. 22/15: On-going activity that will need to be revised as new requirements are issued.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
15104	Steam Generators Access Ports - Existing Material in the Preheater Delays Foreign Material Retrieval	EVENT: Following preheater access port installation, foreign material introduced during machining needs to be removed from inside the steam generator. Existing foreign material inside the preheater region may make it more difficult for the vendor to remove any new foreign material. CAUSE: Existing foreign material inside the steam generator. IMPACT: Delays to the project schedule. May also impact the 40 day chemistry drain requirement on the steam generators (see Risk 14359).		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	31-Aug-17	3	1	3	9	3	1	2	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9685	In Progress	Preheater Access Ports: Testing by Vendor on Modified Mock-Up	Vendor to modify existing preheater access port mock-up to more accurately represent the field conditions (tube pitch, diameter, set-off...) at Darlington and perform testing on the new mock-up to demonstrate that the results are consistent with the results documented in vendor's report DSG0-LR-01.	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17	Feb. 9/17: Latest update from vendor is that testing will be completed and report issued March 8/17. Due date adjusted. Dec. 5/16: Vendor's proposal for modifying the mock-up currently under review by OPG. To be linked to the action once review and update is complete. Target completion for implementing the changes to the mock-up is Jan. 15/17. Testing to be scheduled after mock-up updates are completed and around other vendor commitments.
9687	In Progress	Steam Generators - Preheater Access Ports - Vendor to Update CWP/Schedule to include Planned Retrieval of Machining Chips	The vendor is to update their Comprehensive Work Package (CWP) and schedule to include the planned retrieval of the machining chips during field execution for each of the three preheater access ports. This will include updates and/or additional FME plans to address the machining chips.	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17	Feb. 9/17: Delays in completion of additional preheater testing will delay completion of the CWP. Due date adjusted.

Outage Window	Window Description
037	037 - Secondary Side SG Clean & Install Access Ports

ID	Risk Title	Risk Description		Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13416	Workplace congestion during refurb	EVENT: Workplace congestion due to other project groups causes changes to the detailed plan for the SG project. CAUSE: Other project groups using laydown areas assigned to the SG project. Laydown areas not correctly identified by the project. IMPACT: Delays to the project schedule and/or increased project costs		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Mitigate	01-Nov-18	4	1	2	8	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9194	In Progress	Steam Generators - Summarization of Services in the Site Infrastructure Plan	Summarizing the services required from the vendors given in the Site Infrastructure Plan. Services includes, but are not limited to: -Electrical -Service Air -Breathing Air -Water -Decontamination Services -Active Ventilation -Drains -Radiation Protection Services -Communication Requirements	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17	Nov 3/16: Due Date Updated. Oct 5/16: Action created.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13416	Workplace congestion during refurb	EVENT: Workplace congestion due to other project groups causes changes to the detailed plan for the SG project. CAUSE: Other project groups using laydown areas assigned to the SG project. Laydown areas not correctly identified by the project. IMPACT: Delays to the project schedule and/or increased project costs	9195	In Progress	Update the SATMs	The SATMs will be updated to provide a clear understanding on where work will be taking place to ensure that the work area is available, and that other projects won't be occupying the same space. Is currently in progress; waiting for completion to close out.	Pejman Asgaripour	Iman Afshar	14-Apr-17								

Feb 27/17: SATMs have been approved and are on HOLD for SG Project except for 3 locations in elevations 107.5 and 115 on F-13, M-16 and J-16 Column lines which are submitted and awaiting for CA approval.
Feb 13/17: On weekly status update meeting dated February 9, it has been asked from BWXT to follow up with approval of SATMs and get all approvals by 28-February-2017.
Jan 29/17: Some SATMs have already been approved but for the rest, BWXT will follow up to get the approval by the end of February 2017.
Jan 5/17: Updated delegate. Updated Due Date.
Jan 04/17: A follow up Email has been sent to BWXT to Revise, Update and Re-submit the SATMs according to overall schedule changes. BWXT confirmed that they got approval for SATMs for windows 34 and 37 and pending approval for window 62. See Attached correspondences.
Dec 9/16: Due Date Updated. Description Updated. NOTE: Vendor is off site, and won't be available until next year.
Nov 3/16: Due Date Updated.
Oct 5/16: Action created.

			9196	In Progress	Attend Vault Meetings	Attend the Vault Meetings to prevent possible risks from forming. This will be completed by informing other projects what is required for the SG project, and listening to other projects to understand what they require.	Pejman Asgaripour	Iman Afshar	31-Mar-17								

Feb 13/17: Vault meeting scheduled for every Thursday starting February 23, SG project representative will attend the meeting.
Feb 01/17: No Vault meeting has been scheduled by the Vault coordinator since 23-December-2016.
Jan 24/17: The contact information for the JV person (Dan Olson) who is the coordinator for space assignment inside the vault has been provided to the contractors for assigning the locations for equipment decontamination and storing the insulations.
Jan 5/17: Updated Due Date.
Dec 23/16 Attended the Vault meeting: Congested area for decontamination of the equipment and also location for storage of Insulation removal is a concern
Dec 9/16 Number of people working in the Vault in different project had been discussed for the duration which Window 101 is performing, Window 34 is in parallel and require 8+RPO

Outage Window	Window Description
034	034 - Primary Side SG Layup
037	037 - Sec Side SG Clean & Install Access Ports
062	062 - Primary Side SG Clean and Inspect
105	105 - Vault Projects After Feeder Removal

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14160	Schedule Impact to SG Primary Side Window 062 from Feeder Installation	EVENT: Steam Generator Primary Side Clean Window 062 is impacted by Upper Feeder Installation Window 076 CAUSE: Upper Feeder Installation Window 076 will use all/most float provided which runs to the beginning of Lower Feeder Installation Window (RFR Critical Path) and preventing the Primary Side Window 062 from commencing as suggested in Level 1 IMPACT: The impact will mean that the Steam Generator Primary Side Window 062 will reduce/shorten in duration resulting in the scope of work to not be completed as currently scheduled nor as currently budgeted. Additional shifts may be required to recover by the window finish date. Additional shifts will result in additional costs to the project. Since Steam Generator Primary Side Clean Window 062 is schedule immediately preceding Fuel Load, the impact will be to both the Steam Generator Project and return to service of the unit.	2	Active	Pejman Asgaripour	Melanie Lahti	22-Feb-17	Monitor	01-Apr-18	2	1	4	8	2	1	4	8

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect
076	076 - Upper Feeder Installation

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13302	Foreign Material Enters Steam Generator-Secondary Side	EVENT: Unexpected foreign materials is introduced into station systems during waterlancing and access port installation. This risk does not apply to machining chips entering the steam generator during installation of the preheater access ports (see RMO issue 371 and decision 781. CAUSE: Inadequate human performance, work processes and / or design features. IMPACT: Additional cost and schedule for FME retrieval. May require tube plugging		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	15-Sep-17	3	2	2	6	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1898	In Progress	If vendor supplying FME Retrieval tools and workers, Ensure qualification requirements includes training, mock-ups, etc	If vendor supplying FME Retrieval tools and workers, Ensure qualification requirements includes training, mock-ups, etc	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17	Feb 14, 2017 - FME personel were not included. Request sent to D.Dhar Feb 14, 2017 to provide supporting information for qualification of tooling and personnel for FME Retrieval support activities at site. Awaiting final training plan submission to confirm adequate inclusion of qualification requirements to use vendor supplied tools.
1899	In Progress	SG - Secondary Side - FME Plans and Controls in Place Prior to Field Execution	FME plans and controls in place prior to field execution. includes having a process flowchart on steps to build a new tool for "must retrieve" FME that includes authorization to use.	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17	Feb. 9/17: Preparation of FME plans in progress. Due date adjusted. Dec. 30/16: Decision has been made that OPG FME program will be followed resulting in additional FME plans being prepared and added to the CWPs. New plans are currently undergoing review by OPG FME SPOC. No new tooling is required as part of this project. NOTE: This action does not include the plans for the foreign material generated during preheater access port installation (action #9861) Sept. 19/16: FME plans are part of the CWP. Path forward currently being reviewed regarding which FME program to follow (OPG or vendor). Due date moved to Nov. 15/16 to allow time to revise FME plans based on this decision. FME contingency approach identified via e-mail August 28th. Further work to follow. FME contigency plan will be an appendix to future CWP for secondary side work.

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13411	Steam Generator does not meet dryness criteria as requested by SNC Lavalin	EVENT: Steam generator does not meet the dryness criteria requestedby SNC Lavailin potentially caused by OPG not providing a dry SG to the contractor. CAUSE: Drying performed by layup contractor does not sufficiently dry the steam generator. IMPACT: Cost associated with modification to existing drying system or new pre-maintenance drying required to ensure dryness criteria is met. This could delay execution window start.		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	15-Aug-18	2	1	3	6	2	1	1	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
5227	In Progress	Confirm dryness specification are met from SG Primary side layup	This action is to ensure SG Primary side meets dryness crtieria required for most effective primary side cleaning, and add task in schedule to confirm dryness criteria is met at T-9 (months) for PSC.	Pejman Asgaripour	Mike Lutz	28-Jul-17	July 19, 2016 - SDLU has agreed to incorporate verification and pre-req activities in their schedule to confirm -8 degrees dewpoint is achievable (11% relative humidity at 25 degress celcius). Once SG layup requirements have been achieved and maintained following window 34, ES fox will calibrate the dryers to increase the dryness to meet SG maintenance requirements (Tentatively July 2017). Once this is confirmed, ES fox will change the dryer controls back to layup conditions. Prior to the SG Primary Side Maintenance Window, ES Fox will dry the primary side to -8 degrees dewpoint, in accordance with the SG Contract requirements. TCD moved to 2017 to align with confirmation of dryness capability for SG dryers. June 30, 2016 - Discussion with SDLU DTL regarding capability fo dryness system in order to confirm dry system has capability to dry to SNC required dryness (-8 degrees dewpoint). Due date extended to allow time for assessment. June 6/16: Work order being finalized. Due date moved to July 8/16. March 8, 2016 - ES Fox temporary equipment monitoring project will monitor dryness of SGs. Work Orders and schedule are in progress of being assessed. Once this is finalized, SG Project to communicate with ES Fox to ensure SG dryness criteria is met and maintained prior to SG maintenance window. OPEX from pt. lepreau indicated that vac dry was sufficient for drying. SG will be undergoing addiitonal layup dry.Follow up with layup to determine if they will be monitoring humidity levels, and confirm their target is achieved and maintained per the design requirements.

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14499	Delay in Transfering PSC Flask to Trillium Container	EVENT: As part of the Primary Side Clean (PSC) project, magnetite waste will be collected in a shielding flask that needs to be transferred to a trillium container. Due to this being FOAK, there may be delays in executing this transfer. CAUSE: FOAK work that may result in delays in completing the flask transfer to the container IMPACT: Delay the schedule		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	15-Dec-18	3	1	2	6	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7746	In Progress	Execute Trial Run of PSC Waste Transfer	Execute Trial Run of PSC Waste Transfer in order to mitigate FOAK risk.	Pejman Asgaripour	Mike Lutz	15-Dec-17	June 9, 2016 - Work plan preparation in progress. Stakeholder comments are being incorporated into Work plan and then document to be routed for approval. Work Plan to be used as basis for PSC Waste Transfer Trial run with empty PSC waste container.

ONTARIO POWER GENERATION

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14499	Delay in Transfering PSC Flask to Trillium Container	EVENT: As part of the Primary Side Clean (PSC) project, magnetite waste will be collected in a shielding flask that needs to be transferred to a trillium container. Due to this being FOAK	**Outage Window**		**Window Description**												
			062		062 - Primary Side SG Clean and Inspect												
14585	Work Calendar for OPG Support resources (Ops, Chemistry, RP) does not align with vendor work calendar	Event: Integrated vendor execution schedule duration is extended. Cause: OPG Support resources do not support execution activities on the same work calendar. Impact: Vendor must re-schedule activities on OPG work calendar, resulting in significant increase to work duration and additional cost. May impact predecessor projects and impact chemistry requirements.	3	Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Mitigate	28-Apr-17	2	2	3	6	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7944	In Progress	SG Project - Prepare MOU with Project, and OPG Support Resources (RP, Ops, Chemistry) regarding required Work Schedules	Resolve during vertical integration meetings. Prepare MOU, and get sign off from support resource managers: -Chemistry -Operations -Rad Protection	Pejman Asgaripour	Iman Afshar	31-Mar-17	Feb 13/17: The MOU has been signed by SG Project Director, Chemistry and RP Managers, awaiting for Operations and Construction Oversight managers signature. Jan 17/17: MOU draft has been prepared and distributed for signature between supporting groups such as RP, Construction Oversight, Operations, Chemistry. See attached draft version of the Memorandum. Dec 19, 2016 - TCD revised Sep 8, 2016 - Memo to be routed across different functional stakeholders. Aug 11, 2016 - Memo is in draft and under internal project review							
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			037		037 - Sec Side SG Clean & Install Access Ports												
			062		062 - Primary Side SG Clean and Inspect												
			105		105 - Vault Projects After Feeder Removal												
14775	Station Manipulators may not be available in time for Window 34 execution	EVENT: Station Manipulators are not repaired/decontaminated in time for Window 34 SG Open activities CAUSE: D1711 delay to boiler window, significant repair activities required to tooling. RESULT: Vendor is delayed leading to cost and schedule impacts, and push to establishing layup conditions on SGs.		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Monitor	28-Apr-17	2	1	3	6	2	1	3	6
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14776	TSSA availability may delay documents acceptance as well as ITP hold/witness sign offs	EVENT: TSSA availability may delay documents acceptance as well as ITP hold/witness sign offs CAUSE: TSSA representative is unavailable during ITP holds/witness sign offs IMPACT: Delay to project schedule/increased project costs		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	15-Mar-19	3	2	2	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9095	In Progress	SG TSSA Hold Points Incorporated in Project Schedule	Once SG project ITP's have been reviewed by TSSA and any hold points have been assigned, ensure that all TSSA hold points are incorporated into the project schedule.	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17	Nov. 22/16: Several ITPs currently being revised based on CWP updates and a decision regarding path forward for preheater access ports. ITPs will be sent to TSSA following OPG acceptance. Due date moved to Feb. 2017.							
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			037		037 - Secondary Side SG Clean & Install Access Ports												
			062		062 - Primary Side SG Clean and Inspect												
15106	Steam Generator Access Ports - Foreign Material in Preheater is More Extensive than Expected	EVENT: During inspections of steam generator interior after installation of the preheater access ports it is discovered that the extent of foreign material introduced into the steam generator is more extensive than expected based on testing performed on the mock-up. CAUSE: Differences in material properties and/or internal geometry as a result of operations that could not be anticipated during testing on the mock-up. IMPACT: Schedule delays to accommodate the extra time required to retrieve the material inside the steam generator.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	31-Aug-17	2	1	3	6	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
15106	Steam Generator Access Ports - Foreign Material in Preheater is More Extensive than Expected	EVENT: During inspections of steam generator interior after installation of the preheater access ports it is discovered that the extent of foreign material introduced into the steam generator is more extensive than expected based on testing performed on the mock-up. CAUSE: Differences in material properties and/or internal geometry as a result of operations that could not be anticipated during testing on the mock-up. IMPACT: Schedule delays to accommodate the extra time required to retrieve the material inside the steam generator.	9685	In Progress	Preheater Access Ports: Testing by Vendor on Modified Mock-Up	Vendor to modify existing preheater access port mock-up to more accurately represent the field conditions (tube pitch, diameter, set-off...) at Darlington and perform testing on the new mock-up to demonstrate that the results are consistent with the results documented in vendor's report DSG0-LR-01.	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17								
			9687	In Progress	Steam Generators - Preheater Access Ports - Vendor to Update CWP/Schedule to include Planned Retrieval of Machining Chips	The vendor is to update their Comprehensive Work Package (CWP) and schedule to include the planned retrieval of the machining chips during field execution for each of the three preheater access ports. This will include updates and/or additional FME plans to address the machining chips.	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17								
			Feb. 9/17: Latest update from vendor is that testing will be completed and report issued March 8/17. Due date adjusted. Dec. 5/16: Vendor's proposal for modifying the mock-up currently under review by OPG. To be linked to the action once review and update is complete. Target completion for implementing the changes to the mock-up is Jan. 15/17. Testing to be scheduled after mock-up updates are completed and around other vendor commitments.												
			Feb. 9/17: Delays in completion of additional preheater testing will delay completion of the CWP. Due date adjusted.														
			Outage Window	**Window Description**													
			037	037 - Secondary Side SG Clean & Install Access Ports													
11294	Steam Generator Primary Side Clean Magnetite Contamination Event	EVENT: Loose contamination event during steam generator primary side clean magnetite collection CAUSE: Hose rupture or other issue with the contractor's primary side cleaning equipment. IMPACT: Delay to critical path for the SG project. A large scale contamination event could result in work stoppage of PSC and other refurbishment/operating units work until the affected area is decontaminated.	1	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	04-Jan-19	1	3	5	5	1	2	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			1890	In Progress	complete design reviews and performance mock up demonstrations to ensure process interlocks/connection integrity meets contamination co	Complete design reviews and performance mock up demonstrations to ensure process interlocks/connection integrity meets contamination control requirements. Ongoing discussion with all stakeholders. Services demand will be finalized after schedule integration.	Pejman Asgaripour	Mike Lutz	30-Jun-17	Aug 3, 2016 - PSC validation testing is not scheduled until 2017. TCD updated accordingly.							
			Outage Window	**Window Description**													
			062	062 - Primary Side SG Clean and Inspect													
13919	CWP completion far in advance of execution date may result in CWP revisions/rework	EVENT: Changes are required to the CWP's based on validation testing performed by the contractor prior to field execution. CAUSE: OPG imposing early CWP completion date for CWPs and procedures. IMPACT: Re-work to the CWP's which will be an extra cost to the project. CWP will be aproved in April. The validation testing will take place following CWP approval, which mayresult in revisions to CWP documentation.	1	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Accept	08-Oct-17	5	1	1	5	5	1	1	5
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6142	In Progress	Determine Impact of Validation Testing on PSC CWP	The CWP for primary side clean is being prepared in advance of validation testing at the contractor's facility. Post validation testing the approved CWP needs to be reviewed to determine if the results of the validation testing drives any changes to the CWP.	Pejman Asgaripour	Mike Lutz	14-Jul-17	Nov 8, 2016 - Due Date moved to align with schedule forecast date for the completion of PSC validation testing. Dec. 22/15: Need to revise completion date to align with completion of the validation testing.							
			Outage Window	**Window Description**													
			034	034 - Primary Side SG Layup													
			037	037 - Secondary Side SG Clean & Install Access Ports													
			062	062 - Primary Side SG Clean and Inspect													
14388	Manipulators not available for future units	EVENT: SG primary head manway cover manipulators not available as required in the project schedule for future units (After unit 2 refurb). CAUSE: Unit 2 refurb occurs without any overlap. However, Unit 3 refurb will overlap with Unit 1 refurb. Unit 3 will be using all of the manipulator sets, leaving Unit 1 with no refurb sets. IMPACT: Delays in executing the SG primary side layup activities due to overlap with units using all of the manipulator sets.		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Monitor	15-May-19	5	1	1	5	5	1	1	5
			Outage Window	**Window Description**													
			000	000 – No Window Related													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11278	Damage to Steam Generator Tubes During Access Port Installations	EVENT: Damage to steam generator tubes during access port installations. CAUSE: Potential causes include tool failure or human performance. IMPACT: Additional inspections and/or tube plugging which will impact cost and schedule of SG project. Significant rework adds cost and extends the project schedule.	3	Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	31-Aug-17	1	2	4	4	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1812	In Progress	Access Port Training on Mock-ups	Workers to be trained to operate tooling on mockup, before being approved to execution work at the station	Pejman Asgaripour	Jennifer Nodwell	14-Jul-17	Sept. 19/16: Action title updated based on risk association; due date moved to July 2017 due to window 037 moving in the level 1 schedule.

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11989	IMS Unable to Support Steam Generator Inspections for SG Secondary Side & Bleed Cooler	EVENT: IMS is unable to support steam generator inspections during window 037 and bleed cooler inspections during window 105 as schedued during refurbishment CAUSE: IMS has schedule conflict due to the need to support other planned, forced, or external business activities. IMPACT: Delays to the refurbishment steam generator and bleed cooler execution window and additional costs.	1	Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Mitigate	15-Oct-17	2	1	2	4	1	1	1	1

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports
062	062 - Primary Side SG Clean and Inspect
105	105 - Vault Projects After Feeder Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
12467	Risk of Vendor Default/ Business Continuity	The risk is that the vendor is unable to meet the contractual obligations due to vendor default.	3	Active	Pejman Asgaripour	Melissa Hernandez-Chiang	23-Feb-17	Accept	15-Oct-25	1	3	4	4	1	3	4	4

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13412	Work area restrictions due to Hot Particle	EVENT: Work area restrictions due to high radiological conditions. CAUSE: Hot particle being trapped in the primary side clean system or SG. IMPACT: Schedule delays, costs, and increased dose to crew.		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	15-Oct-17	2	1	2	4	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6144	In Progress	Known Hot Particle Information for Steam Generators	Obtain Dose Data from OPG for any known Hot Particles before each unit outage.	Pejman Asgaripour	Mike Lutz	24-Feb-17	Feb 8, 2017 - ALARA SPOC for SG currently on night shift. Project to follow up week ending Feb 17, 2017 to determine path forward for acquiring information. Jan 20, 2017 - Awaiting dose survey data for Unit 2 Boiler Platforms from ALARA Rep. TCD revised. Dec 15, 2016 - D1321 data requested, and timeline for dose survey data to be available for unit 2 around Boilers form the Refurb ALARA group. TCD updated to Jan 13, 2016, and will be revised if SG unit 2 dose surveys are not available at this time. Dec. 22/15: Due date set as start of refurbishment outage. This may need to be revised.

Outage Window	Window Description
034	034 - Primary Side SG Layup
105	105 - Vault Projects After Feeder Removal

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13967	Transportation of the Shielding Flask Through the Un-zoned Area	EVENT: As part of the Primary Side Clean (PSC) project, magnetite waste will be collected in a shielding flask that needs to be transferred to a trillium container. The project plans to move the full shielding flask from the station to the WFFAA outside through the un-zoned area. As part of a project meeting with the ALARA group it was identified that it may not be possible to transport the shielding flask through the un-zoned area. CAUSE: Decision by RP that the flask cannot be transported through the un-zoned area. IMPACT: New transportation method and / or route will need to be planned. This would lead to increased costs and potential schedule delays.		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	10-Oct-18	2	2	1	4	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
6139	In Progress	Determine Flask Transportation Options	Work with the RP department to determine possible transportation routes for the primary side clean flask once it has been filled with magnetite.	Pejman Asgaripour	Mike Lutz	24-Mar-17	Jan 27 - SNC has provided an assessment for flask transfer. It is not possible to perform 1 lift, due to space constraints. 2 lifts will be required. Lift strategy to be determined through cross functional review meeting. TCD updated. Oct 6/16: Updated Due Date. Sept 8, 2016 - Waste Trasportation Route vetted by ALARA and additional measures incorporated into work plan. Work Plan is still in development due to segment priority (segment 3 work) and potential changes in Candu's waste handling strategy at site. March 8,2016 - Work Plan prepared that identifies transfer route. Walkdown held with Maintenance, ALARA and Waste SPOC to assess transfer route and identify any issues or concerns, and incorporate into Work Plan. TCD for work plan approval is March 31, 2016. Jan 27, 2016: process/approval requirements requested from RP. Awaiting response by Jan 29, 2016.

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14269	Blowdown pipe work causes delays to refill the boiler	EVENT: The boiler blowdown pipe project, which is performed by another project group, takes longer than planned resulting in the SG vendor being unable to complete their work as scheduled. Fill of the SGs cannot take place until the boiler blowdown pipe project is complete and SG vendor cannot finish their work until the SGs have been filled. CAUSE: Boiler blowdown pipe project takes longer than planned. IMPACT: Delays to SG vendor's execution schedule and cost increases due to delay costs. This has the potential to impact the 40 day window however this risk is managed under Risk #14359.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Monitor	31-Aug-17	2	2	2	4	2	2	2	4

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14438	Other projects may impact Bleed Cooler execution window	EVENT: Bleed Cooler inspection window does not have sufficient time to complete inspections CAUSE: The EHS Project can interfere with Bleed Cooler Work. RFR may complete their work (Window 113) earlier than scheduled. IMPACT: Delay or extension to Bleed Cooler inspections start which may not provide enough time to complete inspections before RFR transitions from Sever Bellows (113) to End Fitting Removal (114)		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	29-Sep-17	2	1	2	4	1	1	1	1

Outage Window	Window Description
104	104 - Post Feeder Vault Projects

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14500	Significant amounts of coolant enters SG during Access Port Installation	EVENT: Significant amounts of coolant enters SG during Access Port Installation CAUSE: 1) Inadequate human performance 2) Incorrect work processes IMPACT: Require flush of SG in order to establish chemistry. Can result in schedule delays.		Active	Pejman Asgaripour	Jennifer Nodwell	27-Feb-17	Monitor	30-Aug-17	2	2	2	4	2	2	2	4

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14660	Bleed Cooler work stopped due to loss of contam control	EVENT: During Bleed Cooler inspection work, tritium levels in vault exceed the back condition Maximum Permissible Concentration in Air (MPCa) CAUSE: Loss of contam control (due to dryer issues, tenting effectiveness) IMPACT: All Bleed Cooler work will be stopped. AL1 doors to be closed. Dryers will be required to reduce the tritium levels in the vault to below the MPCa		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	29-Sep-17	2	1	2	4	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8950	Not Started	Assess effectiveness of glove box tenting during D1711	Assess effectiveness of glove box tenting during D1711 and incorporate lessons learned into unit 2 refurb bleed cooler inspections	Pejman Asgaripour	Mike Lutz	31-Mar-17	

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
14660	Bleed Cooler work stopped due to loss of contam control	EVENT: During Bleed Cooler inspection work, tritium levels in vault exceed the back condition Maximum Permissible Concentration in Air (MPCa) CAUSE: Loss of contam control (du	**Outage Window**	**Window Description**													
			105	105 - Vault Projects After Feeder Removal													
14710	First time evolution in Bleed Cooler Inspections scope	EVENT: During DNRU2, Bleed Cooler (2-33320-HX2) inspections are first of a kind evolution and have never been performed before on the DNGS Bleed Coolers. CAUSE: 1) The unavailablity of validated procedures for first time maintenance activities presents some level of unknowns. 2) Schedule integration needs to be completed to ensure footprint + resources are available IMPACT: This can potentially result in adverse cost/schedule/quality impact.	2	Active	Pejman Asgaripour	Mike Lutz	23-Feb-17	Mitigate	29-Sep-17	2	1	2	4	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8954	Not Started	Incorporate lessons learned from D1711 Bleed Cooler inspections into Unit 2 Bleed Cooler during Darlington Nuclear Refurbishment	Incorporate lessons learned from D1711 Bleed Cooler inspections into Unit 2 Bleed Cooler during Darlington Nuclear Refurbishment. During DNRU2, Bleed Cooler (2-33320-HX2) inspections are first of a kind evolution and have never been performed before on the DNGS Bleed Coolers. As a result, the unavailablity of validated procedures for first time maintenance activities presents some level of unknowns. This can potentially result in adverse cost/schedule/quality impact.	Pejman Asgaripour	Mike Lutz	31-Mar-17	Aug 29/16: Action created							
			Outage Window	**Window Description**													
			105	105 - Vault Projects After Feeder Removal													
13968	Munter is Not Available for Bleed Cooler Inspection	EVENT: The risk is that a munter is not available for the bleed cooler inspection. CAUSE: Munter in use by other projects. IMPACT: Increase costs and / or schedule delays.		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	20-Oct-17	1	2	3	3	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8945	Not Started	Confirm with RFR-JV no issues with placement of Munter for Bleed Cooler Inspections during Window 105	Once schedule window is finalized, confirm with RFR-JV that there are no issues with placement of the Munter in the vault prior to start of Bleed Cooler inspections. Refer to RMO action # 8801 for details of the agreement.	Pejman Asgaripour	Mike Lutz	30-Jun-17	Aug 29/16: Action created based on risk meeting							
			Outage Window	**Window Description**													
			105	105 - Vault Projects After Feeder Removal													
14158	Steam Generator Schedule impacts with Emergency Heat Sink (EHS)	Event: Steam Generator Primary Side Clean Window 062 is potentially impacted by a delay to Emergency Heat Sink (EHS) Window 068 CAUSE: Due to delay in Emergency Heat Sink (EHS) Window 068, the SG vendors will not be able to move from the west side boilers to the east side boilers IMPACT: Cost increases due to resource availability, schedule delays impacting the finish date of the Steam Generator Primary Side Clean Window 062, as well as, impacting the return to service since the Fuel Load is immediately succeeding the Steam Generator Primary Side Clean Window 062.	2	Active	Pejman Asgaripour	Melanie Lahti	22-Feb-17	Monitor	02-Jul-18	1	2	3	3	1	2	3	3
			Outage Window	**Window Description**													
			062	062 - Primary Side SG Clean and Inspect													
			068	068 - Emergency Heat Sink													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
15016	Layup Bungs Arrival not in Time for Window 34	EVENT: During testing and analysis of bung components, new design issues may be discovered or fabrication vendor is unable to meet schedule timeline. CAUSE: Additional testing and analysis required prior to procurement/fabrication and delivery of SG layup bungs to site IMPACT: Delays to delivery schedule and impact to Window 34 Start Date.		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Monitor	31-Mar-17	1	1	3	3	1	1	3	3
			Outage Window	**Window Description**													
			034	034 - Primary Side SG Layup													
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11925	Foreign Material Enters Steam Generator-PS	EVENT: Foreign materials are introduced into station systems during divider plate inspections, bunge install, and IMS inspections CAUSE: Inadequate human performance, work processes and design features. IMPACT: Cost and schedule impacts for FME retrieval	1	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Monitor	28-Feb-19	1	1	2	2	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			1898	In Progress	If vendor supplying FME Retrieval tools and workers, Ensure qualification requirements includes training, mock-ups, etc	If vendor supplying FME Retrieval tools and workers, Ensure qualification requirements includes training, mock-ups, etc	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17	Feb 14, 2017 - FME personel were not included. Request sent to D.Dhar Feb 14, 2017 to provide supporting information for qualification of tooling and personnel for FME Retrieval support activities at site. Awaiting final training plan submission to confirm adequate inclusion of qualification requirements to use vendor supplied tools.							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
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Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11925	Foreign Material Enters Steam Generator-PS	EVENT: Foreign materials are introduced into station systems during divider plate inspections, bunge install, and IMS inspections CAUSE: Inadequate human performance, work processes and design features. IMPACT: Cost and schedule															

Outage Window	Window Description
034	034 - Primary Side SG Layup
062	062 - Primary Side SG Clean and Inspect

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11928	Steam Generator Primary Side Cleaning Waste Container Dose Rates or Activity Loading Exceeds Limits	EVENT: The shield flask for primary side cleaning waste collection system does not provide sufficient shielding or the waste collected exceeds licensed activity preventing road shipment offsite. CAUSE: This could be caused by an under estimation in waste volume and/or activity, errors in shielding flask design/selection. IMPACT: Incomplete cleaning or the need to store wastes on site until dose decays to appropriate levels for shipment/license limits for activity.	1	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	28-Feb-19	2	1	1	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1383	In Progress	Investigate location for temporary storage of contingency/partially filled containers	Investigate location for temporary storage for contingency containers, if required.	Pejman Asgaripour	Mike Lutz	17-Mar-17	Jan 12/17: Explore potential use of Retube Waste Storage Facility for temporary storage of PSC waste containter, and waste transfer location. Feb. 26/16: Changed action due date to end of June Jan 27, 2016: SATM request for EFFA laydown area in progress. Refurb Waste Management supporting MOU with station identifying waste container laydown requirements for PSC. Dec. 18/15: Plans for radioactive material shipments being finalized. Due date moved to align with the assessing complete milestone (April 15/16) refurb Ops/maint issued a refurb radioactive storage assessment. Sg has provided input on what's req'd for this project. As the final options for radioactive material storage prior to offsite shipment has not been determined, this action cannot close.

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
12461	Inadequate Quality Control on PSC control software	EVENT: Improper tracking of blast plan and inability to monitor pressure and duration setpoints during primary side cleaning of the SGs. CAUSE: PSC system control software not tested and controlled prior to execution. IMPACT: Blasting of the same tubes more than intended and / or blasting of small radius tube regions at a higher pressure setpoint than what is qualified. This could result in tube damage.	1	Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Mitigate	28-Sep-18	1	2	2	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
3679	In Progress	Inadequate Quality Control for PSC Control Software	-Software Validation on mockup (test failure modes and cleaning sequence) -Implement Procedural controls for software changes/modifications prior to and during execution	Pejman Asgaripour	Mike Lutz	19-Jul-17	Nov 8, 2017 - TCD updated to align with schedule forecast for validation testing completion for PSC System: SG EPC UC PSC On Boiler System - Testing and Commissioning - 4/21/2017 SG EPC UC PSC Process System - Testing and Commissioning - 5/9/2017 SG EPC UC Control Monitoring and Communications - Testing and Commissioning - 6/5/2017 SG EPC UC PSC Robotics and Process System - Testing and Commissioning - 7/19/2017

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13418	Defects in the Shell	EVENT: Will require redesign of port location or require a repair before proceeding. CAUSE: Defects identified in the shell during mag particle and UT scans. IMPACT: This could lead to significant schedule delays and cost impact.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	30-Jun-17	1	1	2	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post				
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score	
13418	Defects in the Shell	EVENT: Will require redesign of port location or require a repair before proceeding. CAUSE: Defects identified in the shell during mag particle and UT scans. IMPACT: This could lead to significant schedule delays and cost impact.	6140	Not Started	Review Results of NDE Scans of the SG Shell	Non-destructive examination (NDE) of the SG shell are scheduled as a pre-req to the installation of the access ports to check for defects in the SG shell. Planned testing includes visual, UT, and/or PT scans. The results of the NDE testing need to be reviewed by OPG to confirm that the planned access port location is acceptable.	Pejman Asgaripour	Jennifer Nodwell	30-Jun-17	Sept. 19/16: Activities moved due to changes in the Level 1 schedule; work now planned for May 2017; due date moved to June 30 2017. Dec. 22/15: Due date of Jan. 30/17 based on the current project schedule. This will need to be confirmed once rev. 0 of the program schedule is released.								
			Outage Window		**Window Description**													
			037		037 - Sec Side SG Clean & Install Access Ports													
13729	Non-adherence to chemistry specified cleanliness requirements during field execution	EVENT: The contractor does not adhere to cleanliness requirements during field execution. CAUSE: Lack of adherence to cleanliness requirements by the contractor during field execution. IMPACT: Negative impact to the plant's system chemistry.	2	Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Monitor	30-Jul-17	2	1	1	2	2	1	1	2	
			Outage Window		**Window Description**													
			034		034 - Primary Side SG Layup													
			037		037 - Sec Side SG Clean & Install Access Ports													
			062		062 - Primary Side SG Clean and Inspect													
			105		105 - Vault Projects After Feeder Removal													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															
13975	Changes to SG Primary Side Inspection window may conflict with IMS support during Darlington and Pickering Planned Outages	EVENT: IMS have committed to the original Refurbishment inspection window in order to coordinate support for Pickering and Darlingnton Planned outages (per IMS blackout dates). As the window moves, it may conflict with the planned outage blackout dates resulting in resource conflicts for Refurbishment and Planned Ouatges. CAUSE: Changes to the SG primary side inspection and maintenance window as work control finalizes and refines the DNRU2 Level 1 Schedule IMPACT: IMS resources not available as required by the SG project. Additional costs to the projects and delays to the execution window	2	Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Monitor	02-Jul-18	1	2	2	2	1	2	2	2	
			Outage Window		**Window Description**													
			062		062 - Primary Side SG Clean and Inspect													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															
14355	ALW sump is filled by SG project or other projects	EVENT: High demand on ALW causes delays to waterlancing CAUSE: Demand due to parallel activities from waterlancing, mod flush, D1711 activities, and other online station activities produces more water than ALW capacity IMPACT: Delays to SG project schedule and threats to 40 day window		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Monitor	10-Sep-17	1	1	2	2	1	1	2	2	
			Outage Window		**Window Description**													
			037		037 - Sec Side SG Clean & Install Access Ports													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															
14359	Extension to 40 day SG Secondary Side Maintenance Window	Event: The maintenance window on the Secondary Side of the SGs may extend beyond the 40 day allowable duration (chemistry constraint) Cause: Due to delays in the schedule and integration with other work groups and resources (IMS, Operations) Impact: The SG project will need specific approved exemption from chemistry to allow a drained state for longer than the allowable duration, which could result in harm to the Steam Generators. To avoid extending beyond this timeframe, the SGs may need to be refilled and then drained to reset the clock. This requires additional support activities and will result in schedule and cost impact to the project.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Monitor	31-Aug-17	1	1	2	2	1	1	2	2	
			Outage Window		**Window Description**													
			037		037 - Sec Side SG Clean & Install Access Ports													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															
14584	Additional Waterlancing Required Post-Inspections	EVENT: After reviewing the post waterlancing inspections it is determined that additional waterlancing and/or flushing is required to adequately clean the SG. CAUSE: Insufficient cleaning by the SG vendor. IMPACT: Delay to the project schedule while additional cleaning occurs. No cost impact since this work is fixed price.		Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Monitor	21-Aug-17	1	1	2	2	1	1	2	2	
			Outage Window		**Window Description**													
			037		037 - Sec Side SG Clean & Install Access Ports													
			There are no Draft, Not Started, In Progress Actions associated with the risk.															

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14662	Radiography in the vault by other projects delays execution of Bleed Cooler Work	EVENT: Radiography in the vault by other projects delays execution of Bleed Cooler work CAUSE: The use of radiography as the inspection method to evaluate weld integrity will require all non-radiography crew personnel to vacate the vault. This will delay all projects, ultimately delaying Bleed Cooler Work IMPACT: Delay to all projects happening at the same time as Bleed Cooler work and delays to Bleed Cooler work		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Monitor	20-Oct-17	1	1	2	2	1	1	2	2

Outage Window	Window Description
105	105 - Vault Projects After Feeder Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14777	Document deficiencies delay CCD/AFS acceptance	EVENT: Document deficiencies delay CCD/AFS acceptance. CAUSE: Deficiencies in documents and completion of documents RESULT: Delay to project schedule		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Mitigate	03-Dec-18	2	1	1	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9525	In Progress	Preparation/Acceptance of Turnover Package for Secondary Side	Preparation and acceptance of a Turnover Package for Window 37 (Secondary Side Work) will create a clear path forward of what is to be expected during execution. This includes the work to be completed, and any paperwork that is required by the project (ie. CCDs, AFSs) for the work completed.	Pejman Asgaripour	Jennifer Nodwell	10-Mar-17	Jan. 19/17: further updates to plan completed; will be routed for review next week; due date adjusted Dec. 30/16: Draft turnover package has been prepared and discussed with RTS group; finalization of plan in progress to route for formal review; due date updated to allow time for document review
9825	In Progress	Preparation/Acceptance of Turnover Package for Primary Side	Preparation and acceptance of one Turnover Package comprised of Window 34, Window 62, and Primary Side Boiler Close, will create a clear path forward of what is to be expected during execution. This includes the work to be completed, and any paperwork that is required by the project (ie. CCDs, AFSs) for the work completed.	Pejman Asgaripour	Mike Lutz	10-Mar-17	Feb 23, 2017: Stakeholder review complete. Routing for signatures. TCD Revised. Jan 31, 2017: Primary Side Turnover Plan submitted for stakeholder review January 26, 2017. Comments expected by Feb 8, 2017. Target for plan approval is February 17, 2017. TCD Revised. Jan 01/17: A draft for Window 34 Turnover package has been prepared. Dec 21/16: Action created.
9826	In Progress	Preparation/Acceptance of Turnover Package for Bleed Cooler Inspections	Preparation and acceptance of a Turnover Package for Window 105 will create a clear path forward of what is to be expected during execution. This includes the work to be completed, and any paperwork that is required by the project (ie. CCDs, AFSs) for the work completed.	Pejman Asgaripour	Iman Afshar	31-Jul-17	Feb 13/17: Turnover package for Windows 34 and 62 has been distributed for stakeholders' signature, the same plan for Bleed coolers (Window 105) is under internal review. Feb 01/17: The Turnover package has been distributed to the stakeholders for review and comment. Jan 03/17: A draft for Turnover Package has been prepared. See Attached drafts of the documents. Dec 21/16: Action created.

Outage Window	Window Description
034	034 - Primary Side SG Layup
037	037 - Secondary Side SG Clean & Install Access Ports
062	062 - Primary Side SG Clean and Inspect
105	105 - Vault Projects After Feeder Removal

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15105	Steam Generator Secondary Side - Failed Zero Power Hot Leak Checks	EVENT: During reactor restart activities, leak checks need to be performed for the newly installed access ports and the existing handholes when the reactor is at zero power hot. CAUSE: Incorrect installation of the access port or handhole covers. IMPACT: Delay to critical path during start-up to retorque the covers (best case) or drain the steam generator and reinstall the covers (worst case).		Active	Pejman Asgaripour	Jennifer Nodwell	09-Feb-17	Mitigate	01-Jun-19	1	2	1	2	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9687	In Progress	Steam Generators - Preheater Access Ports - Vendor to Update CWP/Schedule to include Planned Retrieval of Machining Chips	The vendor is to update their Comprehensive Work Package (CWP) and schedule to include the planned retrieval of the machining chips during field execution for each of the three preheater access ports. This will include updates and/or additional FME plans to address the machining chips.	Pejman Asgaripour	Jennifer Nodwell	24-Mar-17	Feb. 9/17: Delays in completion of additional preheater testing will delay completion of the CWP. Due date adjusted.

Outage Window	Window Description
037	037 - Secondary Side SG Clean & Install Access Ports

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11959	Steam Generator Legacy Foreign Material Cannot Be Removed	EVENT: Steam Generator Vendor FME removal tooling may not be able to support the removal of all known legacy foreign material in hard to reach regions of the steam generator. CAUSE: Legacy FME located in a hard to reach region of the SG that the contractor's tool can't reach. IMPACT: This will result in additonal FME tooling development by the vendor or engineering to disposition leaving material in the SG.	3	Active	Pejman Asgaripour	Jennifer Nodwell	08-Feb-17	Mitigate	30-Aug-17	1	1	1	1	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1899	In Progress	SG - Secondary Side - FME Plans and Controls in Place Prior to Field Execution	FME plans and controls in place prior to field execution. includes having a process flowchart on steps to build a new tool for "must retrieve" FME that includes authorization to use.	Pejman Asgaripour	Jennifer Nodwell	17-Mar-17	Feb. 9/17: Preparation of FME plans in progress. Due date adjusted. Dec. 30/16: Decision has been made that OPG FME program will be followed resulting in additional FME plans being prepared and added to the CWPs. New plans are currently undergoing review by OPG FME SPOC. No new tooling is required as part of this project. NOTE: This action does not include the plans for the foreign material generated during preheater access port installation (action #9861) Sept. 19/16: FME plans are part of the CWP. Path forward currently being reviewed regarding which FME program to follow (OPG or vendor). Due date moved to Nov. 15/16 to allow time to revise FME plans based on this decision. FME contingency approach identified via e-mail August 28th. Further work to follow. FME contigency plan will be an appendix to future CWP for secondary side work.

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12460	Inadequate Quality Control for Waterlancing Control Software	EVENT: Honing issues, system shutoff parameters, and / or repeat lane visits during waterlancing of the steam generator. CAUSE: Inadequate control of the waterlancing control software. IMPACT: Inadequate sludge removal and / or steam generator asset damage.	1	Active	Pejman Asgaripour	Jennifer Nodwell	09-Feb-17	Monitor	14-Jul-17	1	1	1	1	1	1	1	1

Outage Window	Window Description
037	037 - Sec Side SG Clean & Install Access Ports

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13398	Execution Quality-CWP & ITPs are in compliance with vendor's quality program	EVENT: The contractor performs execution activities without a robust CWPs and ITPs. This could lead to damage to the Steam Generators/Bleed Cooler, ineffective cleaning, or loss of FME controls. CAUSE: The contractor does not properly execute the work. IMPACT: Damage to the Steam Generators/Bleed Cooler, ineffective cleaning and / or loss of FME controls. This could lead to increased costs and schedule delays.		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Monitor	20-Apr-17	1	1	1	1	1	1	1	1

Outage Window	Window Description
034	034 - Primary Side SG Layup
037	037 - Secondary Side SG Clean & Install Access Ports
062	062 - Primary Side SG Clean and Inspect
105	105 - Vault Projects After Feeder Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14270	High Pressure Water Pumps may not be available for NR Waterlancing Campaign [for future units]	EVENT: The Darlington High Pressure water pumps used for waterlancing are not availabe for the refurb vendor to use during the water lancing CAUSE: The Waterlancing campaign during the applicable outage is delayed IMPACT: A delay in the start of the refurb secondary side maintenance window which will have adverse cost impact to the SG project and interfacing projects Pumps may not be available for future units. See Action ID 00007745 for obtaining MOU for waterlancing pumps to use for future units.	3	Active	Pejman Asgaripour	Jennifer Nodwell	09-Feb-17	Monitor	31-Jan-18	1	1	1	1	1	1	1	1

Outage Window	Window Description
037	037 - Secondary Side SG Clean & Install Access Ports

There are no Draft, Not Started, In Progress Actions associated with the risk.

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14357	Contractor Field Staff Impact Station Operations	EVENT: Contractor field staff negatively impact station operations CAUSE: Lack of contractor awareness of impact to station operations during field execution IMPACT: Delay to the station schedule		Active	Pejman Asgaripour	Jennifer Nodwell	09-Feb-17	Monitor	11-Jan-19	1	1	1	1	1	1	1	1

Outage Window	Window Description
034	034 - Primary Side SG Layup
037	037 - Sec Side SG Clean & Install Access Ports

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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Process Owner: L. Ren
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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14357	Contractor Field Staff Impact Station Operations	EVENT: Contractor field staff negatively impact station operations CAUSE: Lack of contractor awareness of impact to station operations during field execution IMPACT: Delay to the station schedule	062		062 - Primary Side SG Clean and Inspect												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14358	Contractors Field Staff Not Prepared To Perform Field Work	EVENT: Contractor field staff are not prepared (knowledge, experience) to perform field work CAUSE: Contractor field staff lack required qualifications RESULT: Delay to the execution schedule and rework Risk raised on OPEX based on the VVRS project		Active	Pejman Asgaripour	Mike Lutz	16-Feb-17	Monitor	10-Jul-18	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			037		037 - Sec Side SG Clean & Install Access Ports												
			062		062 - Primary Side SG Clean and Inspect												
			105		105 - Vault Projects After Feeder Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14373	Demin Water not available for Waterlancing	EVENT: High demand on demin water supply causes delays to waterlancing CAUSE: Demand due to parallel activities from waterlancing, mod flush. Both require demin water IMPACT: Delays to the Project Schedule		Active	Pejman Asgaripour	Jennifer Nodwell	09-Feb-17	Monitor	10-Sep-17	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			037		037 - Sec Side SG Clean & Install Access Ports												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14510	Steam Generators Primary Side Dry Layup Cover	EVENT: The nuts holding the dry layup cover that is installed on the primary side of the steam generator for refurbishment loosen following a seismic event CAUSE: The dry layup cover was not designed to maintain a leak tight seal during a seismic event. IMPACT: Insufficient drying of the PHT system after a seismic event due to leakage through the dry layup cover.		Active	Pejman Asgaripour	Iman Afshar	27-Feb-17	Monitor	15-Dec-18	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			034		034 - Primary Side SG Layup												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Turbine Generator -																	
13309	TG Crane, all lifting Equipment and Tools Availability/Capability, Hoisting and material handling [All Units]	EVENT: The condition of the crane is degraded to a point where it cannot support the requirements of the TG project. Due to the condition of the crane there is a possiblity of performing standard maintenance, incremental maintenance or a modification to the crane in order to meet the TG project requirement. OPEX on similar installation has shown that the crane would require modification in order to meet the load demand required for this turbine work. Also as per WANO OPEX the performance trend in rigging, lifting and material handling activities has worsened at nuclear stations. Rigging, lifting and material handling events could have adversely affected nuclear safety systems/components and conventional safety. CAUSE: Additional aspects is the residual reliability risk of the TH Crane after refurbishment. If the TH Crane experience any break down during the critical path of the TG window, cost and schedule will be negatively impacted. Also, there is a risk related to plant integration, related to any forced outages or other station emergency requirements to use the cranes which may supersede TG Project needs, resulting in negative impact to cost and schedule. The potential to drop heavy loads in the plant areas is a matter of great concern. During the Turbine Generator refurbishment work there will be various lifting and rigging of suspended loads, and the movement of non suspended loads. A number of critical lifts will occur for weights greater than 50 tones that will cause a great deal of damage if dropped. IMPACT: This event can lead to cost and schedule impact. This risk is an extension to program risk 888, it deals with specialized lifts that the contractor will perform for Turbine Generator Work.	1	Active	Peter Moore	Mina Boghdady	22-Feb-17	Mitigate	21-Oct-21	3	3	4	12	2	3	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8468	In Progress	Heavy lifting practicing due dilegence	As per Heavy Lift work including Main Stator lift and Crane Overhaul lesson learned, OPG to recognize the dangers present in heavy lifts by researching OPEX cases that went wrong. Practice due diligence during the planning phases leading up to the stator replacement.	Peter Moore		15-Oct-21	
8688	Not Started	TG Crane load test	Perform the 125% load test after the refurbishment of the transmission for crane 1 & 2.	Peter Moore	Mina Boghdady	28-Feb-17	[Mina B. 10/17/2016] Due to discovery work on Crane Maintenance Window #2 which scoped into window#3; the load test has been postponed to February 2017. The discovery work identified requires the replacement of all gear assembly on the main hoist for both cranes.

Outage Window	Window Description
061	061 - Turbine Generator Major Overhaul
100	100 - TG and Condenser Work Phase I

13419	Turbine and Excitation Controls Software Qualification Report (SQR) Risk to Quality/Schedule [Unit 3]	EVENT: Software Qualification Report is required prior to the FAT testing and for JV to complete all deliverables for Release 2 in March 2016. Any delay will affect the FAT testing and impact the schedule. CAUSE: There are two aspects to the risk:Technical: Due to OPG-specific criteria which drives the Turbine and Excitation Controls software to a higher level, [redacted] Commercial: Alstom has provided OPG a preliminary gap analysis identifying the Turbine and Excitation Controls software that Alstom intend to provide Software Qualification Reports (SQR). The preliminary gap analysis also identifies software which, due to contractual difference of position, Alstom does not intend on providing SQRs for. [redacted] Although software qualification is progressing on track, but there will be a residual risk until FAT testing can be completed. As per OPG project and GE correspondences, GE remains responsible for their software, in case any post-FAT modification is required and results of FAT test must be correctly interfaced with the final software qualification reports. IMPACT: This can lead to schedule and cost impact on the overall project. SCR N-2015-10744.	3	Active	Todd Josifovski	Soorena Merat	23-Feb-17	Mitigate	01-May-17	3	2	4	12	1	2	4	4

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13575	Stator Mid Section transportation risk [Unit 3]	EVENT: As part of the TG scope of work a new generator stator mid section is being procured. CAUSE: The transportation of the stator mid section is currently in the ESES scope. However a risk is imposed that infrastructural upgrades (St. Mary's Cement Dock, Gravel road connection, etc.) are required to complete the stator transportation. IMPACT: The infrastructure upgrade will impact cost.	1	Active	Peter Moore	Arber Puci	24-Feb-17	Mitigate	30-Nov-17	3	3	1	9	3	2	1	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			7951	In Progress	TG- Darlington Dock assesment	The TG project believes that receiving the stator via water is the most feasible solution and provides better value for money than the rail option. The project has contracted IMS to perform an assessment of the dock structure to ensure that the dock can safely withstand the weight of the stator. IMS and their diving team will obtain concrete samples and they will submit a report with the assessment of the dock.	Peter Moore	Arber Puci	10-Feb-17	As per IMS latest update, an extension till February 2017.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
11217	TG- Lack of skilled and experienced EPC Vendor Staffing [All Units]	EVENT: Lack of Skilled and experienced craft labour, QC and supervision resources in Definition, Planning and Execution phases for TG project for performing the work as per schedule with sufficent quality; avoiding any potential rework. CAUSE: Ability of vendor to hire the experienced and skilled personnel and the unavailability of experienced and skilled personnel. IMPACT: Potential rework that can impact cost and schedule.	1	Active	Peter Moore	Ron Aranha	23-Feb-17	Mitigate	31-Jan-18	2	2	4	8	2	2	3	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.		Peter Moore	Arber Puci	10-Mar-17								
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
13531	TG Risk of Schedule Delay / Cost Due to OPG and Vendor Handoffs / Dependent Activities [All Units]	EVENT: Due to multiple vendor handoffs, the TG contracting strategy has been optimized to reflect strengths of vendors and internal OPG groups involved. CAUSE: Late or incomplete handoffs, or late completed activities may result in delay or rework by other vendors or OPG groups. IMPACT: However the risk is that there will be schedule delay or additional costs due to the multiple handoffs / dependent activities between OPG / Alstom / JV / IMS.	1	Active	Peter Moore	Arber Puci	24-Feb-17	Monitor	01-Jun-18	2	3	4	8	2	3	4	8
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13973	TG - IMS work window for TG could coincided with their blackout dates [All units]	EVENT: IMS has been hired by the refurb organization to perform inspection on the Turbine Generator and Auxiliaries. CAUSE: The Refurb execution window is posing a risk since IMS work window for TG could coincided with their blackout dates that IMS has identified for support of planned outages in PNGS and DNGS as part of generation plan initiative. IMPACT: There is significant impact on schedule that might occur. The SG bundle and TG project could fall into the same category.	1	Active	Peter Moore	Arber Puci	24-Feb-17	Monitor	01-Jun-18	2	1	4	8	2	1	4	8
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11221	TG Risk of Schedule delay due to inefficient vendors cooperation/interface on technical information (i.e Design) [All Units]	EVENT: The selected vendor may not obtaining, or not obtaining on time, technical information from the ESES required to support the T/G work due to lack of EPCs ability to obtain required information from ESES. CAUSE: Inability to answer/excessive response time RFI's from EPC. IMPACT: There might be schedule delay and additional cost	3	Active	Todd Josifovski	Peter Moore	22-Feb-17	Mitigate	31-Dec-17	2	2	3	6	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			9956	In Progress	TG-implement ITF reporting	Implement of the ITF reporting in the weekly JV meeting.		Peter Moore	Ken Lee	31-Dec-17								
			9957	In Progress	TG - tripartite meetings	Hold JV/GE/OPG tripartite meetings in 2017.		Peter Moore	Arber Puci	31-Dec-17								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
11250	TG Discovery work scope caused by inspections with impact on long lead items or major repairs [All Units]	EVENT: The risk is that parts/resources for contingent (inspection based) work is not readily available when needed to support TG objectives or when major repairs are required. CAUSE: Following inspections, material lead time is evaluated against recommended contingent work and adverse schedule impact may result. (such as thyrisistor inspection but not including major items such as Stress Corrosion Cracking on the Turbine Rotor) IMPACT: It will affect greatly affect the TG window risking to make it a critical path.	1	Active	Todd Josifovski	Peter Moore	23-Feb-17	Monitor	29-Dec-17	2	3	3	6	2	3	3	6
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11965	TG - Risk of EPSCA Costs Above Current Estimate [All Units]	EVENT: There is a large number of craft, technical or supervision labor required for this refurbishment project. CAUSE :The risk is that upon hiring craft, technical or supervision labour, a greater percentage of workers than estimated must be drawn from beyond the range that requires maximum per diems (lodging etc.). IMPACT: Resulting in greater expenditures than estimated.	1	Active	Todd Josifovski	Pejman Asgaripour	22-Feb-17	Monitor	30-Jun-25	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12302	TG- Unavailablity of validated procedures due to first time evolution in the maintenance scope [Unit 2]	EVENT: During the DNRU2 there is a number of maintenance activities that will represent a first of a kind evolution and have never been performed before on the DNGS such as Removal of turbine spindles and lower blade carriers. CAUSE: The unavailablity of validated procedures for first time maintenance activities presents some level of unknowns. IMPACT: This can potentially result in adverse cost/schedule/quality impact.	2	Active	Peter Moore	Arber Puci	23-Feb-17	Mitigate	30-Dec-17	2	2	3	6	1	2	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7749	In Progress	TG- CWP package field assesment	The CWP prepared for the U2 execution will be field walk down by the foreman and OPG oversight to asses its field execution and identify and pre-reqs and materials that will be required to be completed prior to breaker open. First of a Kind in segement-1 include 1- CT and HV Bushing replacements 2- Drain and Dry of the Stator Core 3- Condenser Seal replacement 4- IPB, Air box and Terminal Box work	Peter Moore	Mina Boghdady	01-Mar-17	[MINA B. 08AUG2016] The CWP Field walkdowns will be completed for both segments (Windows 061 &100) for the TG Bundle in March 2017. Currently all CWP required for TG Segement-1 (Window 100) have been walked down and as per the developed process comments are currently being dispositioned.							
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.	Peter Moore	Arber Puci	10-Mar-17								
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
12401	Misunderstanding the requirements, or errors in vendor's submittals to OPG [All Units]	EVENT: Vendor is submitting a large number of documents to OPG. The requirements for this deliverables are listed in the VOIR interface requirements. CAUSE: Vendor may misunderstand VOIR interface requirements, requirements for integration, or requirements (deliverables) of the contract and there can be quality and level of errors on vendor's submittals to OPG for review. IMPACT: There is a potential delay in completing the milestone and can impact the schedule.	3	Active	Peter Moore	Ken Russell	22-Feb-17	Monitor	31-Dec-17	2	2	3	6	2	2	3	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13443	TG – Risk of Ability to Implement OPG Project Team Resourcing Assumptions [Unit 2]	EVENT: In support of 4D estimating in 2014, TG implemented a variable resourcing profile for OPG core project management personnel, assuming that personnel could be ramped up and down as dictated by the Refurbishment outage schedules and work profile. CAUSE: Due to considerations of maintaining project team continuity, this resourcing profile cannot be realized or can only be partially realized. IMPACT:The impact would be increased cost to the project.	1	Active	Peter Moore	Pankaj Chauhan	24-Feb-17	Monitor	31-Dec-17	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14112	TG- Potential added cost due to in-situ retaining ring inspection [all units]	EVENT: There is a high possibility of GE to implement in situ retaining ring inspection. CAUSE: Due to the unavailability of power sources in the plant to remove the retaining ring for inspection. GE, OPG and JV are discussing various method of performing the retaining ring inspection. IMPACT: This inspection has the potential to carry extra cost for OPG.	3	Active	Peter Moore	Marcel Fiterau	23-Feb-17	Accept	31-Jan-17	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14113	TG - GE to incorporate comments of stator third party review [Units 3&4]	EVENT: GE is producing a new stator mid section and producing the technical specification of this product. CAUSE: GE has already incorporated OPG's comments on the U3 Generator Stator technical documents. A generator expert has been hired by OPG to perform a third party review of the U3 Generator Stator technical documents. IMPACT: Based on the comments to be provided by the generator experts there is a risk of additional costs to GE and also a potential for a schedule delay.	4	Active	Peter Moore	Arber Puci	24-Feb-17	Monitor	31-Jan-18	2	2	3	6	2	2	3	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14588	TG- Inadequate/unavailable Tooling [All units]	EVENT: The Turbine Generator work requires specialty tooling. As part of the contract between JV and OPG, OPG will provide all the tooling but JV will be maintaining them for the duration of the work. CAUSE: Tooling unavailability has the potential to affect work, the specialty tooling has to be manufactured if its broken or lost. There is also a potential of a station outage to occur at the same time therefore limiting the availability of the tools. Impact: Tooling unavailability can impact schedule.	2	Active	Peter Moore	Arber Puci	24-Feb-17	Mitigate	01-Jun-18	2	1	3	6	1	1	2	2
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14952	TG - Potential Impact due to application and modification of Work Protection/Permits	EVENT: The operation support for the TG project is schedule is on a 5 days x 10 hours Monday to Friday schedule, and, if needed can accommodate some changes to / and or delays to the implementation of the work protection requirements (operational permits) during the week end or the back shift. OPEX shows that initial application of Permits and inevitable required modifications to the permits will delay the Project Progress CAUSE: In case there is no support available for the week end or the back shift some required permit evolution will not occur therefore impacting and delaying the work downstream. IMPACT: This has the potential to impact the schedule		Active	Peter Moore		24-Feb-17	Accept	25-Dec-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13552	TG - ESES Vendor Technical Field Advisor (TFA) Greater Support than Anticipated [All units]	EVENT: TG project is hiring Technical Field Advisors from the vendor to provide guidance and support execution. The ESES Vendor (Alstom/GE) provided an estimate of the expected cost based on the TG project schedule. CAUSE: The ESES Vendor (Alstom/GE) Technical Field Advisor costs can be greater than anticipated in the estimate provided. This could be due to additional technical field support required to shore up EPC vendor capability/expertise, additional support to support the schedule, or due to major discovery work extending the overall turbine window. IMPACT: This can lead to extra cost.	1	Active	Todd Josifovski	Arber Puci	24-Feb-17	Monitor	28-Mar-18	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13553	TG - Risk of Additional Spare Parts Costs as a Result of Maintenance OPEX [All Units]	EVENT: Extended maintenace will be performed on U2 during refurb outage. The lesson learned and the findings will be used to plan subsequent units 1,3,4. Cause: For subsequent units 1,3,4, additional turbine generator spare parts would need to be procured from OEM or OPG Warehouse, will be required as a result of maintenance OPEX gained on the first unit. IMPACT: this can result in additional cost impact. No schedule impact.	1	Active	Todd Josifovski	Arber Puci	24-Feb-17	Accept	31-Dec-17	2	2	1	4	2	2	1	4
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14905	HFE integrated validation post-DCAVR	EVENT: Based on previous OPEX, performing integrated validations on large, complex systems should be performed in a timely manner to avoid expensive engineering re-work or critical path delays to Refurbishment. CAUSE: Any discovery issues that affect the designs associated with the Turbine Generator control systems and the supporting/interfacing systems will likely be complex and require substantial time to rectify. Performance of the HFE integrated validation post-DCAVR and towards breaker open for Unit 3 increases this risk to the project. IMPACT: Part of the risk is the time necessary to design and implement any computer-based changes, as the lead time for such changes are generally long. The worst-case scenario is computer interface design changes that impact the critical path for the TG control system and HMI that threatens the Unit 3 refurbishment timeline.	1	Active	Peter Moore	Rajeev Leekha	28-Feb-17	Monitor	31-May-19	1	2	4	4	1	2	4	4
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11242	TG FME Event Adverse Impact on Cost , Schedule and Equipment [All Units]	EVENT: There is a unique risk of FME associated with turbine generator. CAUSE: The FME controls implemented by the vendor might not be adequate, resulting in an FME event. Oversight finds FME process issues, or an FME event occurs. IMPACT: FME event adverese impact on cost , schedule and equipment.As per contract, JV will be responsible for any rework due to an FME event caused by their resources, but OPG will incurr the cost for any overall delay or any indirect impact due caused by this events.	1	Active	Todd Josifovski	Peter Moore	23-Feb-17	Monitor	31-Dec-17	1	2	3	3	1	2	3	3
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9958	Draft	TG- FME qualification check on	Perform a spot check on JV's FME qualification on the trades.		Peter Moore	Ken Lee	01-May-17							
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
14414	TG - TG window will negatively impact D1831 outage [Unit 2]	EVENT: During the U2 refurbishment outage the TG window has a set window to ensure that it will not overlap with any scheduled station outage. CAUSE: There is a potential that if there is a schedule push on the TG window it can impact the D1831 outage. IMPACT: Overlapping refurb and planned TG outages can impact have a negative impact on multiple items such as on tooling release, floor space, etc. P50 schedule contingency.	1	Active	Peter Moore		24-Feb-17	Monitor	30-Nov-17	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11744	TG OEM's control systems may not meet IESO's requirements [Units 3,4 and 1]	EVENT: Turbine & Excitation Controls equipment replacement scope requires completion of a System Impact Assessment from the IESO. There current exceptions from IESO for the Darlington Station will be required to be meet. CAUSE: There is a chance that OEM vendor's excitation system design will not meet IESO regulatory requirements, or that late identified requirements will impact cost/schedule. Darlington IESO exceptions shall be continued to be enforced and will be addressed by design. IMPACT: By not meeting the IESO requirements, for the worst case scenario the generator will not be able to connect to the grid. The project will be required to work critical path until the control parameters of the generator have been manipulated to meet the requirements to connect to the grid. This will cost an overall refurbishment outage delay. On the best case scenario the IESO will conditionally allow the unit to connect to the grid until the next unit outage, where the project will require performing the dynamic commissioning portion again to modify the generator parameter in order to meet the IESO requirements. This will have an impact on the cost of the project.	2	Active	Peter Moore	Ken Russell	23-Feb-17	Mitigate	29-Dec-17	1	1	2	2	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			9959	Draft	TG - Excitation Control FAT	Completion of the Excitation control FAT, to demonstrate performance. The process of the FAT with any open issues will be tracked to completion.		Peter Moore	Ken Russell	14-Apr-17							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
13444	TG - JV may not be compliant to OPG request [All Units]	EVENT: During review cycle or oversight performed OPG can provide various request to vendors for changes. CAUSE: The JV may not be compliant with OPG requests and not seeking prior approval to making changes to engineering related work urgency. IMPACT: This has the potential to lead to re-work on JV part, which can affect the overall schedule and cost. This risk deals with quality of work issues and non-compliance to procedures issues.	3	Active	Peter Moore	Mina Boghdady	22-Feb-17	Monitor	31-Dec-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13730	TG - contractor may not adhere to OPG chemistry requirements [All Units]	EVENT: OPG Refurb Chemistry has prepared procedures for the cleaninlines requirements to be used in the plant by the contractors during refurbishment. CAUSE: There is a risk that the contractor may not adhere to cleanliness requirements during field execution that may adversely impact plant's system chemistry. IMPACT: This had the potential to have a cost and schedule impact on the project.	3	Active	Peter Moore	Dave Owens	24-Feb-17	Monitor	01-Jun-18	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
			100		100 - TG and Condenser Work Phase I												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14030	TG - New Stator Midsection risk [Unit 3]	EVENT: The TG project is procuring a new stator to be used on U3 generator from Alstom. The new stator is specified and expected to be delivered on site as a direct replacement item. CAUSE: There is a risk that the new stator can arrive at the darlington site not with the right components and the design does not have the correct specification. Therefore the stator funclionality and operability is not similar to the original. IMPACT: This will lead to great schedule and cost impact.	3	Active	Peter Moore	Arber Puci	24-Feb-17	Monitor	31-May-21	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Turbine Generator - 73032																	
14409	TG - FOAK Generator Stator drain and dry during U2 refurbishment [Unit 2]	EVENT: The generator stator is infrequently drained, and has never been vacuum dried. This will have to be completed as part of the TG refurbishment scope. CAUSE: This is a First of a Kind Work Cost, of particular concern are: 1)The lack of skilled and experienced labour. 2)The unavailability of a validated procedure due to the task's status as FOAK work. 3)Vacuum pump details/tool and process not finalized. 4) Stator winding corrosion if inadequately dried. IMPACT: Schedule and cost impacts could result from unknown factors during the drain and dry process.	1	Active	Peter Moore	Arber Puci	28-Feb-17	Mitigate	25-Jan-17	2	3	4	8	1	2	2	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			7749	In Progress	TG- CWP package field assesment	The CWP prepared for the U2 execution will be field walk down by the foreman and OPG oversight to asses its field execution and identify and pre-reqs and materials that will be required to be completed prior to breaker open. First of a Kind in segement-1 include 1- CT and HV Bushing replacements 2- Drain and Dry of the Stator Core 3- Condenser Seal replacement 4- IPB, Air box and Terminal Box work		Peter Moore	Mina Boghdady	01-Mar-17	[MINA B. 08AUG2016] The CWP Field walkdowns will be completed for both segments (Windows 061 &100) for the TG Bundle in March 2017. Currently all CWP required for TG Segement-1 (Window 100) have been walked down and as per the developed process comments are currently being dispositioned.				
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.		Peter Moore	Arber Puci	10-Mar-17							
			Outage Window		**Window Description**												
			100		100 - TG and Condenser Work Phase I												
Project: Turbine Generator - 73272																	
14407	TG - FOAK Cost and schedule impact due to high voltage bushings and current transformers replacement [Unit 2]	EVENT: The high voltage bushings and transformers haven't been replaced since installation in original turbine generator set erection. CAUSE: Due to this being a first of a kind work, particular concern are: 1. Size/Weight, tight working space and lack of experience with the required tooling 2. CT Wiring Connections correct installation and quality control 3. HV Bushing Replacement and potential damage to spare bushing used for mock-up 4. IPB Disassembly, first time evoluation (FME, control of parts, spares, mechanical joints, broken parts). IMPACT: Unknown factors in the replacement of high voltage bushings and transformers could impact the cost and schedule for the generator portion of TG refurbishment scope.	2	Active	Peter Moore	Arber Puci	24-Feb-17	Mitigate	31-Aug-17	2	2	4	8	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.		Peter Moore	Arber Puci	10-Mar-17							
			Outage Window		**Window Description**												
			100		100 - TG and Condenser Work Phase I												
			661		661 - TG Major Overhaul												
Project: Turbine Generator - 73273																	
13863	Turbine Controls / Excitation Controls / Hydraulics unexpected issues/delays in static or dynamic commissioning [Units 3,4 and 1]	EVENT: The modification to be implemented, the turbine controls, excitation controls and hydraulic controls are being upgraded. This new modification will be tested during static and dynamic commissioning. CAUSE: There is various unexpected issues that can occur during the static or dynamic commissioning from schedule window delay to the whole system not functioning or behaving as expected. IMPACT: This can lead to a big impact on the cost, schedule and might delay the entire refurbishment of U3.	1	Active	Peter Moore	Arber Puci	24-Feb-17	Mitigate	01-Jul-21	2	2	4	8	1	2	4	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8685	In Progress	TG FSMS installation	A full scope maintenance simulator will be installed to provide an opportunity to test the system before.		Peter Moore	Soorena Merat	30-Nov-17							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
Project: Turbine Generator - 73277																	
14410	TG - FOAK LP Spindles Removal for U2 refurbishment [Unit 2]	EVENT: Due to the legacy strategy of maintenance in place the LP spindles have not been removed since turbine generator set erection. The scope also requires first time removal of other components such as lower Steam Inlet Casing (SIC) and complete disassembly work on the intercept valves. Of particular concern are: Tooling Uncoupling of turbines Testing/Commissioning LP spindle shift Resource Challenges Lifting Equipment Procedures Discovery Work or unexpected issues during first time removals OPG unsuccessfully attemptted to disasseble these intercept valves before. CAUSE: This is a first of a kind work conducted with a high potential for risk. IMPACT: These tasks could involve impacts to cost/schedule if not planned adequately or executed as planned.	1	Active	Peter Moore	Mina Boghdady	28-Feb-17	Mitigate	01-Jun-18	3	4	4	12	2	3	3	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			7749	In Progress	TG- CWP package field assesment	The CWP prepared for the U2 execution will be field walk down by the foreman and OPG oversight to asses its field execution and identify and pre-reqs and materials that will be required to be completed prior to breaker open. First of a Kind in segement-1 include 1- CT and HV Bushing replacements 2- Drain and Dry of the Stator Core 3- Condenser Seal replacement 4- IPB, Air box and Terminal Box work		Peter Moore	Mina Boghdady	01-Mar-17	[MINA B. 08AUG2016] The CWP Field walkdowns will be completed for both segments (Windows 061 &100) for the TG Bundle in March 2017. Currently all CWP required for TG Segement-1 (Window 100) have been walked down and as per the developed process comments are currently being dispositioned.				
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.		Peter Moore	Arber Puci	10-Mar-17							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14410	TG - FOAK LP Spindles Removal for U2 refurbishment [Unit 2]	EVENT: Due to the legacy strategy of maintenance in place the LP spindles have not been removed since turbine generator set erection. The scope also requires first time removal of other components such as lower Steam Inlet Casing (SIC) and complete disassembly work on the intercept valves. Of particular concern are: Tooling Uncoupling of turbines Testing/Commissioning LP spindle shift Resource Challenges Lifting Equipment Procedures Discovery Work or unexpected issues during first time removals OPG unsuccessfully attemptted to disasseble these intercept valves before. CAUSE:	8688	Not Started	TG Crane load test	Perform the 125% load test after the refurbishment of the transmission for crane 1 & 2.	Peter Moore	Mina Boghdady	28-Feb-17	[Mina B. 10/17/2016] Due to discovery work on Crane Maintenance Window #2 which scoped into window#3; the load test has been postponed to February 2017. The discovery work identified requires the replacement of all gear assembly on the main hoist for both cranes.							
			Outage Window		**Window Description**												
			061		061 - Turbine Generator Major Overhaul												
14407	TG - FOAK Cost and schedule impact due to high voltage bushings and current transformers replacement [Unit 2]	EVENT: The high voltage bushings and transformers haven't been replaced since installation in original turbine generator set erection. CAUSE: Due to this being a first of a kind work, particular concern are: 1. Size/Weight, tight working space and lack of experience with the required tooling 2. CT Wiring Connections correct installation and quality control 3. HV Bushing Replacement and potential damage to spare bushing used for mock-up 4. IPB Disassembly, first time evoluation (FME, control of parts, spares, mechanical joints, broken parts). IMPACT: Unknown factors in the replacement of high voltage bushings and transformers could impact the cost and schedule for the generator portion of TG refurbishment scope.	2	Active	Peter Moore	Arber Puci	24-Feb-17	Mitigate	31-Aug-17	2	2	4	8	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.	Peter Moore	Arber Puci	10-Mar-17								
			Outage Window		**Window Description**												
			100		100 - TG and Condenser Work Phase I												
			661		661 - TG Major Overhaul												
14409	TG - FOAK Generator Stator drain and dry during U2 refurbishment [Unit 2]	EVENT: The generator stator is infrequently drained, and has never been vacuum dried. This will have to be completed as part of the TG refurbishment scope. CAUSE: This is a First of a Kind Work Cost, of particular concern are: 1)The lack of skilled and experienced labour. 2)The unavailability of a validated procedure due to the task's status as FOAK work. 3)Vacuum pump details/tool and process not finalized. 4) Stator winding corrosion if inadequately dried. IMPACT: Schedule and cost impacts could result from unknown factors during the drain and dry process.	1	Active	Peter Moore	Arber Puci	28-Feb-17	Mitigate	25-Jan-17	2	3	4	8	1	2	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7749	In Progress	TG- CWP package field assesment	The CWP prepared for the U2 execution will be field walk down by the foreman and OPG oversight to asses its field execution and identify and pre-reqs and materials that will be required to be completed prior to breaker open. First of a Kind in segement-1 include 1- CT and HV Bushing replacements 2- Drain and Dry of the Stator Core 3- Condenser Seal replacement 4- IPB, Air box and Terminal Box work	Peter Moore	Mina Boghdady	01-Mar-17	[MINA B. 08AUG2016] The CWP Field walkdowns will be completed for both segments (Windows 061 &100) for the TG Bundle in March 2017. Currently all CWP required for TG Segement-1 (Window 100) have been walked down and as per the developed process comments are currently being dispositioned.				
			8687	In Progress	TG expectations document for OPG TFAs	Prepare a expectation document for OPG Technical Field Advisor that will support contractor during execution.	Peter Moore	Arber Puci	10-Mar-17								
			Outage Window		**Window Description**												
			100		100 - TG and Condenser Work Phase I												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Unit Islanding -																	
14351	Refurb resources unavailable to support project execution [No Window Related]	Event: Station and Corporate resources supporting Islanding project execution as Refurb resources are unavailable. Several specialized resources are required to execute the Islanding scope including Safety System-qualified Control Techs to perform tie ins for the Negative Pressure Containment pre-req project. These resources may be unavailable or not duplicated in the Refurb organization. Cause: Specialized skill sets and delay in refurb functional support staffing result in the requirement to use resources from other groups in OPGN. Impact: Additional costs will be incurred to fund the support that is not available in Refurb, in addition, schedule delays may be encountered if special skill set staff is unavailable, and as gap support is obtained.	3	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	15-Jun-19	4	1	2	8	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8275	In Progress	Obtain commitments for support from refurb staff	Obtain commitments for support from refurb staff prior to work execution, to identify any resource gaps. Obtain additional funding required for resources outside of refurb.		Bert Boston	Sarah Elliott	15-Jun-19								
			10105	In Progress	Obtain Committments From NR OPS & MTCE to support Window 137	There is a risk that NR OPS & MTCE may not be able to support 24x7 coverage of Window 137. Islanding will need to obtain and confirm this support to prevent delays on the critical path schedule.		Bert Boston	Sarah Elliott	15-Mar-17	10-Feb-17: OPS & MTCE currently unable to forecast their resource distribution. OPG project lad to follow up on developments 1-Mar-17: OPs support verified. Awaiting MTCE support.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
13478	A lead-in task may not be completed before islanding work is scheduled to begin. [Window 023]	Event: Lead-in tasks for Islanding work not completed as scheduled. Cause: Before Islanding work can begin, there is lead-in work which must be completed first. Current issues affecting lead-in tasks are Work Plan and field execution quality. Schedule changes and integration issues by work control could also impact Islanding scheduled work. Impact: If pre-reqs are not completed as planned, Islanding work must be delayed with potential burn rate cost increases.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	15-Apr-17	3	1	2	6	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			9708	In Progress	Ensure materials are ready for advancing defuel schedule.	There is a risk that Islanding may not be prepared to execute with the new schedule alignment. Islanding will work with the JV and monitor progress to ensure readiness of work. Specifically, the team will monitor the progress of the materials for the following CWPs: 2124, 2126, 2127, 2128, ,2129, 2130&(A), 2135, 2137, 2185, 2187		Bert Boston	Mehri Molanaie	10-Mar-17	30-Jan: 2124-Few outstanding materials-need date is ASAP 2126-Materials Procured 2127-2130, 2185-Most materials outstanding 2135, 2137, 2130A, 2187-Several outstanding Materials 6-Feb-17: 2185, 2124, 2135 are still have outstanding material, being monitored daily. Any risks will be communicated to the scheduling team. 15-Feb-2017: Pre-Fabricate Materials for L5 in CWP 2185 have been pushed to the 23rd of Feb. TCD shifted accordingly. 21-Feb-2017: Pre-fabrication materials are still an issues. Current issues with CWP 2135, 2137, 2127, 2128, 2129 and 2185. Shielding for 2124 is also expected to arrive on the 10 of Mar. 28-Feb-17: JV has indicated that the outstanding pre-fabricated material for CWP 2135, 2137, 2127, 2128, 2129 and 2185 will be completed by the 5-Mar. Shielding is expected to arrive 10-Mar.							
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
14036	Risk to EQ qualification/fitness for service of Unit 4 Calandria Seal [No Window Related]	[Execution Phase] Event:Risk to EQ qualification/fitness for service of Unit 4 Calandria Seal Cause: During replacement of the Unit 4 calandria seal in the VBO the outer calandria seal was damaged. Due to contact with the outer and inner seal, a piece of rubber on the inner seal became dislodged during removal of the outer seal. This is documented in JV NCR 001107-00-00-NC-0162 and SCR D-2015-22043. Impact:As a result there is a risk that the Unit 4 seal may no longer be EQ qualified or fit for service and may require replacement.	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Mitigate	31-Mar-17	2	2	3	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14036	Risk to EQ qualification/fitness for service of Unit 4 Calandria Seal [No Window Related]	[Execution Phase] Event:Risk to EQ qualification/fitness for service of Unit 4 Calandria Seal Cause: During replacement of the Unit 4 calandria seal in the VBO the outer calandria seal was damaged. Due to contact with the outer and inner seal, a piece of rubber on the innter seal became dislodged during removal of the outer seal. This is documented in JV NCR 001107-00-00-NC-0162 and SCR D-2015-22043. Impact:As a result there is a risk that the Unit 4 seal may no longer be EQ qualified or fit for service and may require replacement.	5988	In Progress	JV to provide NCR to disposition Unit 4 Calandria Seal Damage	Due to damage on the Unit 4 outer calandria seal that occured the JV is to provide a disposition to NCR 001107-00-00-NC-0162 that addresses the seal design margin and EQ basis.	Bert Boston	Mehri Molanaie	31-Mar-17	7June: walkdown report and disposition still not ready. 26-Aug-15: NCR Dispositions are still with engineering TCD Oct 31st. 21-Oct-16: JV to revise NCR based on OPG comments. NCR TCD 15 Nov. 6-Jan-17: OPG still waiting on NCR, NO JV TCD at the moment. 30-Jan-17: due to resource issue, JV has asked for an extension until 28-Feb-17. 28-Feb-17: Due to resource issues, JV has still note completed the NCR. TCD 31-Mar							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
15109	Risk that Pressure Test may exceed current schedule on P6 [window 024]	Event: Execution of pressure test extends beyond currently allocated schedule of 105 hrs in P6. Per LRTE review, the test would reasonably take 132 hours if we have no leaks, and a successful leakage rate at each phase. Impact: Critical Path delays and financial impacts.		Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	03-Apr-17	3	2	2	6	3	2	2	6
			Outage Window		**Window Description**												
			024		024 - Containment Pre Test, Achieve Dew Point & Containment Test												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14166	Possible hoisting and/or rigging failure for the bulkheads [Window 23, 88]	[Execution Phase] EVENT: While hoisting and/or rigging the bulkheads, there is a possibility that the hoisting and/or rigging will fail. Risk of occurrence is relatively low, however consequence is significant. CAUSE: This is a unique lift as a counterbalance is required. General hoisting and rigging mitigation is captured in Risk 888 however this risk will capture elements specific to this lift. IMPACT: If failure occurs while over duct significant damage could occur to the plant.		Active	Bert Boston	Mehri Molanaie	17-Feb-17	Mitigate	24-Mar-17	1	3	4	4	1	3	4	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6316	In Progress	Review hoisting and rigging plans for bulkhead installation	Review JV's hoisting and rigging plan for installing bulkhead to prevent hoisting and/or rigging failure while installing the bulkhead.	Bert Boston	Mehri Molanaie	24-Mar-17	Reviewer to be identified. 7June: no reviewer identified yet, 7-Sept-16: OPG awaiting newly revised plan. MTL to investigate 14-Oct-16: OPG still awaiting document 14-Dec-16: OPG awaiting document, TCD pushed to 30th Dec. 20-Jan-17: Majority of plans have been review and accepted. Awaiting confirmation for completion of reviews. 6-Jan-17: Plan is currently with SME for review. 11-Jan-!7: Plan has been reviewed and sent back to JV. TCD 20 Jan. 30-Jan-17: Plans have been reviewed, signed and completed. A meeting with the CNSC has been completed regarding the plans. JV to completed resulting actions from meeting. 6-Feb-17: Lift plans for vertical bulkheads are under review. 13-Feb-17: One plan is remaining for the Seal Plugs. Currently with OPG for review, this item has a need date of 1-Mar-17							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14166	Possible hoisting and/or rigging failure for the bulkheads [Window 23, 88]	[Execution Phase] EVENT: While hoisting and/or rigging the bulkheads, there is a possibility that the hoisting and/or rigging will fail. Risk of occurrence is relatively low, however consequence is significant. CAUSE: This is a unique lift as a counterbalance is required. General hoisting and rigging mitigation is captured in Risk 888 however this risk will capture elements specific to this lift. IMPACT: If failure occurs while over duct significant damage could occur to the plant.	6318	In Progress	Inspect hoisting and rigging equipment	To prevent hoisting and/or rigging failure while installing the bulkhead, Islanding will inspect the hoisting and rigging equipment. Inspections were completed at the factory and will be monitored and completed Just In Time (i.e. equipment to be inspected as it is needed on the field). Several trigger dates have been identified, and will be updated on a weekly basis.	Bert Boston	Mehri Molanaie	15-Mar-17	To Be completed in parallel with hoisting set-up. 11-Jan-17: FAT successfully executed for lifting beam. Inspections for remaining hoisting and rigging set-up TCD 20th Jan 20-Jan-17: Inspections for remaining equipment set up to occur closer to execution date. TCD 31-Jan 28-Feb-17: During field inspection of hoisting/rigging equipment, it was determined that the current lift plan (for the counter beam) was inadequate as the JV was not following the procedure. Work was stopped, and the plan was revised accordingly. 6-Mar-17: All bulkheads have been installed with OPG/CNSC witnessing. Action to remain open for the duration of shielding installation.								

Outage Window	Window Description
023	023 - Install Bulkheads
088	088 - Bulkhead Removal

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
14961	Risk that stored Islanding materials may become lost or damaged during refurbishment	Event: Stored materials which will be needed after refurbishment activities may become lost or damaged. Cause: Improper storage, poor turnover of item location, poor oversight of material transportation. Impact: Costs and critical path delays	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	2	2	2	4	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9377	In Progress	Track location of stored Islanding materials (non-Containment Isolations related) during refurbishment	Islanding team to track essential stored materials during refurbishment. By knowing the material's location, the chance of improper storage/ lost of materials decrease. This includes the following: OH180 chips for button-up modification Button-up lamacoids Spill Skid cabinet airlock restraints	Bert Boston	Sarah Elliott	31-Mar-17	16-Nov-16: Oh180 currently stored at CM shop, el 107.5. See attached email. Window lamacoids are in assessing's possession. Translucent lamacoid currently being procured. 31-Jan-17: OH180 & lamacoids still at current location. Spill Skid cabinet is currently at the mech. mtce. laydown area. 1/2 of the A/L restraints are on sight, and the other half is currently at the Whitby warehouse. 1-Mar-17: A/L restraints located U4 100 El.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15164	Risk that EPG3 installation work will be extended prevent final barriers installation [no window]	Event: EPG3 completion may run longer than expected. Currently, A small portion of the barriers work (completion of external pathway) remains outstanding as the construction work for EPG3 prevents installation activities. EPG3 is expected to be completed by April 2017, however, there still remains a risk of the work not being completed on time, thus pushing Barriers work further. Cause: Delays in construction. Impact: Schedule delays for the Construction Islanding Barriers project.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Monitor	30-Apr-17	2	1	2	4	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
10119	Draft	Actions for Barriers CCF	Islanding Project Team to: 1.) Update p6 to accommodate revised Barriers Schedule 2.) Update AS7 to inject new WO for the remaining tasks 3.) Create risk and action on RMO tool for CCF-complete 4.) Update Ecosys	Bert Boston	Sarah Elliott	31-Mar-17	

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15099	Risk that materials are not ready for installation during the post defuel windows [window 023].	Event: Materials for the Containment Isolations project may not be procured, kitted/staged (including having history dockets filed) in time for installation in the field in the post defuel islanding windows. Cause: Delays in manufacturing, errors in documentation. Impact: Critical path delays/financial costs		Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	10-Mar-17	1	2	3	3	1	2	3	3

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
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Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
15099	Risk that materials are not ready for installation during the post defuel windows [window 023].	Event: Materials for the Containment Isolations project may not be procured, kitted/staged (including having history dockets filed) in time for installation in the field in the post defuel islanding windows. Cause: Delays in manufacturing, errors in documentation. Impact: Critical path delays/financial costs	9708	In Progress	Ensure materials are ready for advancing defuel schedule.	There is a risk that Islanding may not be prepared to execute with the new schedule alignment. Islanding will work with the JV and monitor progress to ensure readiness of work. Specifically, the team will monitor the progress of the materials for the following CWPs: 2124, 2126, 2127, 2128, ,2129, 2130&(A), 2135, 2137, 2185, 2187	Bert Boston	Mehri Molanaie	10-Mar-17	30-Jan: 2124-Few outstanding materials-need date is ASAP 2126-Materials Procured 2127-2130, 2185-Most materials outstanding 2135, 2137, 2130A, 2187-Several outstanding Materials 6-Feb-17: 2185, 2124, 2135 are still have outstanding material, being monitored daily. Any risks will be communicated to the scheduling team. 15-Feb-2017: Pre-Fabricate Materials for L5 in CWP 2185 have been pushed to the 23rd of Feb. TCD shifted accordingly. 21-Feb-2017: Pre-fabrication materials are still an issues. Current issues with CWP 2135, 2137, 2127, 2128, 2129 and 2185. Shielding for 2124 is also expected to arrive on the 10 of Mar. 28-Feb-17: JV has indicated that the outstanding pre-fabricated material for CWP 2135, 2137, 2127, 2128, 2129 and 2185 will be completed by the 5-Mar. Shielding is expected to arrive 10-Mar.								
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
14714	Inadequate shielding from radiaiton in Bunker areas may result in elevated vault radiation levels [window 25]	Event: Inadequate shielding in Bunker areas (located down beside the north and south of the calandria) may cause higher than expected levels of radiation in the refurbishing vault. There is a possibility that the fields shining up into the vault will be high enough to either restrict access in these areas or vacate the vault. Cause: Currently no plans in place to determine the need of radiation shielding in these areas. Impact: Possible restriction of movement/evacuation of vault if the radiation levels are deemed too high. This will result in critical path delays.		Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	30-Apr-17	1	2	2	2	1	2	2	2
			Outage Window		**Window Description**												
			025		025 - Install Bulkhead Shielding												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14830	Rental Compressors may not be available to perform containment pressure tests during refurbishment [Window 024]	Event: Rental compressors may not have valid CRN numbers, preventing their use for the containment pressure test. Cause: The compressors used for pressure tests are supplied by two companies located outside of Canada. The majority of their clients are located within the U.S, thus they usually do not have valid CRN numbers on their equipment. A CRN number is issued by the TSSA, and is needed in order for the compressors to operate within Canada. OPEX from the VBO tests in 2009 and 2015 show issues arising from invalid CRN numbers on rental equipment. Impact: Cost and Critical Path impacts	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	31-Mar-17	1	2	2	2	1	2	1	2
			Outage Window		**Window Description**												
			024		024 - Containment Pre Test, Achieve Dew Point & Containment Test												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12250	A second set of Bulkhead panels are not available should the 1st and 2nd unit outages overlap. [No Window Related]	[Execution Phase] Event: A second set of Bulkhead panels are not available should the 1st and 2nd unit outages overlap. Cause: The risk is that Unit 3 will come down early (see Risk 678) which may result in overlapping with Unit 2 outage and there will not be a second Bulkhead available. This would require expedited procurement of a second bulkhead set Based on unlapping of therefurb first and second outages, an economic decision (DRAS 539) has been made to postpone fabrication of a second bulkhead until it is required for overlapping of the 2nd and 3rdrefurb outages. Impact: Schedule delay and material cost	1	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Accept	31-Jan-18	1	1	1	1	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8265	In Progress	Review date requirements of second set of Bulkheads	Review the actual date requirements of the second set of bulkhead panels to determine when they are actually needed.	Bert Boston	Mehri Molanaie	28-Apr-17	24-Aug-16: A review for the need of a second set of bulkheads will be conducted 2 years prior Unit 1 breaker open (i.e. TCD of mid Mar 2019). 21-Oct-16: Islanding given direction to order 2nd set. Team to investigate the exact date when the order can be completed.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Unit Islanding - 73066																	
15060	Potential vendor delays could lead to stalled execution of TCB Pressure Test [window 024].	Event: Vendor is unprepared for execution of the Temporary Containment Boundary Pressure Test. Cause: Delays in WPL/CWP preparation, late identification of material issues due to inadequate statusing, late pre-fabrication. Impact: Critical Path delays/Financial Costs	4	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	10-Mar-17	1	1	1	1	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8889	In Progress	Complete contingency planning for pressure test failure.	Complete contingency planning for pressure test failure. This includes contingency activities in P6, tasks assessed and preapproved planning available.	Bert Boston	Mehri Molanaie	15-Mar-17	21-Oct-16: JV will be creating a contingency planning and associated WO for any repairs identified as immediately needed if there is a pressure test failure, test abortion and retesting is required. The WO instructions is to include specific instructions/support required from JV Civil Engineering and/or Resident Engineering to procedurally instruct how the repair is to be performed. JV will be procuring materials to support contingency repairs. The contingency WO will align and referenced in CWP 2187 - UNIT 2 TEMPORARY CONTAINMENT BOUNDARY COMMISSIONING PRESSURE TEST AND LEAK SEARCHING which currently provides detailed work instructions for any contingency repairs that are required. Continue to monitor to see if WO & WO tasks are correctly integrated into CWP. 21-Nov-16: Action on track. 19-Dec-16: Follow up e-mail sent to JV. JV assessing to update WO with contingency tasks. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: Decision matrix created, JV to finalize and issue. 18-Jan-17: P6 scheduling remaining from JV. TCD 28th Jan 6-Feb-17: Waiting upon REV2 of WPL & CWP 2187. 22-Feb-17: Waiting upon REV2 of WPL & CWP 2187. New revised TCDs show dates of 28-Feb-2017. 28-Feb-17: TCDs for the WPLs and CWP have been moved. CWP 2187 TCD 8-Mar. NK38-WPL-34200-0596707 & NK38-WPL-34200-0596901 TCD 15-Mar.

Outage Window	Window Description
014	014 - Containment Mod Commissioning
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test

Project: Unit Islanding - 73457																	
13346	Assumptions made for the Spill response strategy may become invalidated as planning progress [Window 113]	Event: The Islanding spill response strategy was developed based on assumptions in the level 1 refubishment outage plan at the time the strategy was authored. Cause: Invalidated assumptions made for the spill response strategy Impact: Major changes to the refurbishment outage planning logic (e.g. Heat Transport flush) may impact or invalidate the assumptions of the spill response strategy and contingency plans which will require rework for the project.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Oct-17	3	1	1	3	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8268	In Progress	Check Status of A/R and confirm status of materials	Check status of A/R 28178551. Validate all assumptions made in the spill contingency plan. Find status of materials needed for contingency plan.	Bert Boston	Sarah Elliott	31-Oct-17	7-Sept-16: Once the AR 28178551 assignments are completed, the revised procedure document NK38-OM-38000-05 is reviewed (as per TPAR NR000305), and once the pump / hose & fittings are staged, action can be completed. Several A/R assignments are against other groups, which will not be finished until 2017.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13346	Assumptions made for the Spill response strategy may become invalidated a	Event: The Islanding spill response strategy was developed based on assumptions in the level 1 refubishment outage plan at the time the strategy was authored. Cause: Invalidated assu															
			Outage Window		**Window Description**												
			113		113 - Sever Bellows												
12436	NR project groups may be planning to execute scope on systems, structures, or components that make up the new containment boundary on the refurbishment unit. [Window 23, 85]]	Event: Because the design for the temporary containment boundary that is going to be established on the refurbishment unit is not yet finalised and other work is progressing in parallel, there is a risk that other NR project groups may unknowingly be planning to execute scope on systems, structures, or components that will make up the new containment boundary on the refurbishment unit. Cause: Design work and installation planning happening in parallel. Impact: This may lead to engineering rework to revise designs, cost increases, and schedule delays.	4	Active	Bert Boston	Sarah Elliott	01-Mar-17	Monitor	15-Jun-19	1	1	1	1	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			10209	Draft	Re-review Revision 1 of SIP to	Islanding Series lead to re-review rev001 SIPs.	Bert Boston	Chris	31-May-17								
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			085		085 - AL Closed & Pressure Test												
Project: Unit Islanding - 73461																	
11933	U1 calandria seal will no longer be EQ qualified if there are outage delays exceeding expected life of the seal [No Window Related]	[Execution Phase] Event: The calandria seal will no longer be EQ qualified if there are outage delays exceeding expected life of the seal Cause: If the outage of Unit 1start is delayed >6 months past Feb 2021 (Start of Unit 1) this will exceed the EQ qualification life of the calandria seal for Unit 1 Impact:Resulting in a cost and schedule impact	1	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Mitigate	31-Oct-17	4	2	3	12	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5955	In Progress	Investigate the margin on the seal for unit 1	The CVS material is qualified as per EQ governance to LOCA + LOECI dose. The required Total Integrated Dose (TID) used as input to the EQ qualification included normal dose from operations + accident dose. Currently, the Unit 1 CS is qualified for a normal dose of 228 kEFPH, as per NK38-TSQ-34200-10001 R00. Current kEFPH numbers in N-PLAN-01060-10002 R016 suggest that the seal will be within limits as listed above. This action is to track updates on the kEFPH margins annually. See attached email for more information.	Bert Boston	Mehri Molanaie	31-Oct-17	JV EQ SPOC has provided preliminary analysis indicating additional margin may be possible. By 29April16, document in ITF and put A/R in asset suite.							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
12391	Critical Path extension in refurb unit due to inadequate Vault Vapour Recovery System performance. [Window 137]	Event: Delays to Containment Pressure tests to commission the Bulkhead due to high vault humidity. Cause: The pressure tests require low vault humidity which is obtained through efficient operation of the Vault Vapour Recovery System (VVRS). A pre-req project is being executed to address inadequate performance of the VVRS. This also impacts the time required to reduce tritium to allow both airlock doors open. Current unit Vault Vapour Recovery System reliability and efficiency levels are low which is currently acceptable because a common containment structure provides Vault Vapour Recovery Systemredundancy from other units. Installation of the containment Bulkhead will eliminate the redundancy for the Refurb unit and reduce the redundancy for the operating station. Impact: Inadequate performance of the refurb unit Vault Vapour Recovery System will potentially delay obtaining the required humidity levels for testing and delay critical path	3	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	3	1	2	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			2172	In Progress	Develop plan for optimizing efficiency and reliability of Vault Vapour Recovery System in U2	Monitor station progress on Vault Vapour Recovery repairs. If repairs are not planned to be completed by then refurb will develop an action plan for assessing and taking necessary actions to ensureoptimum efficiency and reliability of Vault Vapour Recovery Systemin U2	Bert Boston	Sarah Elliott	28-Apr-17	Systems Available for refurb initiative in progress. There are currently no significant reliability issues with the VVRS system that will impact refurb. No requirement to take action at this point Continue to monitor until the start of NR -Action YCD pushed to end of March to see VVRS performance during execution of W137.							
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11449	Failure of Containment Boundary pressure tests resulting in critical path delays [Window 024, 085]	[Execution Phase] Event: Failure of Containment Boundary pressure tests resulting in critical path delays Cause: The specified leak rates may not be achieved which would require the leak to be found, addressed, and the pressure test repeated. Possible failure mods are as follows: Portions of the U2 and U3 new Temporary Containment Boundary have never been part of the containment boundary and therefore have never been pressure tested. This includes the calandria seal, SDC room wall, and vertical BH. This new boundary may contain leak paths in the form of concrete cracks, leaks around EP's or weld cracks. There may be unusual system alignments during the pressure tests which may inadvertently introduce leak paths or damage systems which would in turn leak. Unit 2 and Unit 3 permanent bulkheads could fail the commissioning pressure test. Leaking closure plugs may cause leakage into PHT or increase humidity levels in the vault causing inaccurate readings or allow air into the PHT system which would indicate a leak. leakage of new BH panels Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	14-Apr-17	2	1	2	4	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8857	In Progress	Ensure contingency materials are ordered for concrete repairs during pressure test	Failure of the pressure test for the Temporary Containment Boundary may occur due to damage on the Concrete walls within the vault. To ensure minimal delays for the concrete wall repair, all contingency materials will be ordered and onsite ahead of the pressure test.	Bert Boston	Mehri Molanaie	07-Mar-17	21-Oct-16: Grout ordered, contingency plan being built into CWP. 21-Nov-16: Action on track 14-Dec-16: New TCD for materials. 19-Dec-16: Follow up e-mail sent to JV. PO is being placed to procure contingency materials. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: OPG to follow up with JV procurement. 6-Feb-17: Material ordered but not onsite. 28-Feb-17: Material delivery has been estimated for 7-Mar-17.
8889	In Progress	Complete contingency planning for pressure test failure.	Complete contingency planning for pressure test failure. This includes contingency activities in P6, tasks assessed and preapproved planning available.	Bert Boston	Mehri Molanaie	15-Mar-17	21-Oct-16: JV will be creating a contingency planning and associated WO for any repairs identified as immediately needed if there is a pressure test failure, test abortion and retesting is required. The WO instructions is to include specific instructions/support required from JV Civil Engineering and/or Resident Engineering to procedurally instruct how the repair is to be performed. JV will be procuring materials to support contingency repairs. The contingency WO will align and referenced in CWP 2187 - UNIT 2 TEMPORARY CONTAINMENT BOUNDARY COMMISSIONING PRESSURE TEST AND LEAK SEARCHING which currently provides detailed work instructions for any contingency repairs that are required. Continue to monitor to see if WO & WO tasks are correctly integrated into CWP. 21-Nov-16: Action on track. 19-Dec-16: Follow up e-mail sent to JV. JV assessing to update WO with contingency tasks. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: Decision matrix created, JV to finalize and issue. 18-Jan-17: P6 scheduling remaining from JV. TCD 28th Jan 6-Feb-17: Waiting upon REV2 of WPL & CWP 2187. 22-Feb-17: Waiting upon REV2 of WPL & CWP 2187. New revised TCDs show dates of 28-Feb-2017. 28-Feb-17: TCDs for the WPLs and CWP have been moved. CWP 2187 TCD 8-Mar. NK38-WPL-34200-0596707 & NK38-WPL-34200-0596901 TCD 15-Mar.

Outage Window	Window Description
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
085	085 - AL Closed, Shielding Removal & Pressure Test

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11950	Containment Isolation work in the Fuel Handling duct could increase the critical path schedule and lead to cost overruns due to fueling requirements [Window 23, 88]	[Execution Phase] Event:The critical path isolation of the refurb unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. The frequency/availability and duration of no-fueling windows is determined by operating unit zone levels, trolley reliability and required trolley maintenance. Cause: Reasons for no fueling windows not occurring as planned could include unit zone conditions and trolley reliability. The JV planning basis is that any work below the 100m elevation 87% efficient for U2 BH install and drops to 50% for U2 removal and all other work on subsequent unit. This risk documents delay above and beyond the JV planning basis. Impact:If no fueling windows are shortened or do not occur per plan, critical path schedule delays will result as well as cost overruns due to crew standby time. This risk is to identify project level impacts. Program risk #685 is to identify impact at the program level (i.e. critical path that affects all of NR)*QUAD CHART RISK*	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	1	3	3	1	1	3	3
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			088		088 - Bulkhead Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11993	Containment boundary calandria seal may fail during interspace pressure test during NR outage	[Execution Phase] Event: Containment boundary calandria seal may fail during interspace pressure test during NR outage. Risk may not pass initial testing. Cause:Seal degradation overtime and Units 2 and 3 were exposed to a vault pressure test after initial installation. Impact: significant scheduling impact on critical path if seal needs to be replaced. Note, based on knowledge gained during seal testing during previous outages, seal would have to catastrophically fail.	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	01-Jan-20	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11486	Inadequate Bulkhead shielding may result in work stoppages at the vault during station fuelling operations [Window 025]	[Execution Phase] Event:Shielding may not provide adequate protection during fuelling operations resulting in work stoppages. Cause: Cause can be due to design deficiency, manufacturing deficiency, and error in modeling. Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Accept	14-Apr-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			025		025 - Install Bulkhead Shielding												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Project: Unit Islanding - 73462

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12391	Critical Path extension in refurb unit due to inadequate Vault Vapour Recovery System performance. [Window 137]	Event: Delays to Containment Pressure tests to commission the Bulkhead due to high vault humidity. Cause: The pressure tests require low vault humidity which is obtained through efficient operation of the Vault Vapour Recovery System (VVRS). A pre-req project is being executed to address inadequate performance of the VVRS. This also impacts the time required to reduce tritium to allow both airlock doors open. Current unit Vault Vapour Recovery System reliability and efficiency levels are low which is currently acceptable because a common containment structure provides Vault Vapour Recovery Systemredundancy from other units. Installation of the containment Bulkhead will eliminate the redundancy for the Refurb unit and reduce the redundancy for the operating station. Impact: Inadequate performance of the refurb unit Vault Vapour Recovery System will potentially delay obtaining the required humidity levels for testing and delay critical path	3	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	3	1	2	6	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2172	In Progress	Develop plan for optimizing efficiency and reliability of Vault Vapour Recovery System in U2	Monitor station progress on Vault Vapour Recovery repairs. If repairs are not planned to be completed by then refurb will develop an action plan for assessing and taking necessary actions to ensureoptimum efficiency and reliability of Vault Vapour Recovery Systemin U2	Bert Boston	Sarah Elliott	28-Apr-17	Systems Available for refurb initiative in progress. There are currently no significant reliability issues with the VVRS system that will impact refurb. No requirement to take action at this point Continue to monitor until the start of NR -Action YCD pushed to end of March to see VVRS performance during execution of W137.

Outage Window	Window Description
137	137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11449	Failure of Containment Boundary pressure tests resulting in critical path delays [Window 024, 085]	[Execution Phase] Event: Failure of Containment Boundary pressure tests resulting in critical path delays Cause: The specified leak rates may not be achieved which would require the leak to be found, addressed, and the pressure test repeated. Possible failure mods are as follows: Portions of the U2 and U3 new Temporary Containment Boundary have never been part of the containment boundary and therefore have never been pressure tested. This includes the calandria seal, SDC room wall, and vertical BH. This new boundary may contain leak paths in the form of concrete cracks, leaks around EP's or weld cracks. There may be unusual system alignments during the pressure tests which may inadvertently introduce leak paths or damage systems which would in turn leak. Unit 2 and Unit 3 permanent bulkheads could fail the commissioning pressure test. Leaking closure plugs may cause leakage into PHT or increase humidity levels in the vault causing inaccurate readings or allow air into the PHT system which would indicate a leak. leakage of new BH panels Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	14-Apr-17	2	1	2	4	2	1	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8857	In Progress	Ensure contingency materials are ordered for concrete repairs during pressure test	Failure of the pressure test for the Temporary Containment Boundary may occur due to damage on the Concrete walls within the vault. To ensure minimal delays for the concrete wall repair, all contingency materials will be ordered and onsite ahead of the pressure test.	Bert Boston	Mehri Molanaie	07-Mar-17	21-Oct-16: Grout ordered, contingency plan being built into CWP. 21-Nov-16: Action on track 14-Dec-16: New TCD for materials. 19-Dec-16: Follow up e-mail sent to JV. PO is being placed to procure contingency materials. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: OPG to follow up with JV procurement. 6-Feb-17: Material ordered but not onsite. 28-Feb-17: Material delivery has been estimated for 7-Mar-17.
8889	In Progress	Complete contingency planning for pressure test failure.	Complete contingency planning for pressure test failure. This includes contingency activities in P6, tasks assessed and preapproved planning available.	Bert Boston	Mehri Molanaie	15-Mar-17	21-Oct-16: JV will be creating a contingency planning and associated WO for any repairs identified as immediately needed if there is a pressure test failure, test abortion and retesting is required. The WO instructions is to include specific instructions/support required from JV Civil Engineering and/or Resident Engineering to procedurally instruct how the repair is to be performed. JV will be procuring materials to support contingency repairs. The contingency WO will align and referenced in CWP 2187 - UNIT 2 TEMPORARY CONTAINMENT BOUNDARY COMMISSIONING PRESSURE TEST AND LEAK SEARCHING which currently provides detailed work instructions for any contingency repairs that are required. Continue to monitor to see if WO & WO tasks are correctly integrated into CWP. 21-Nov-16: Action on track. 19-Dec-16: Follow up e-mail sent to JV. JV assessing to update WO with contingency tasks. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: Decision matrix created, JV to finalize and issue. 18-Jan-17: P6 scheduling remaining from JV. TCD 28th Jan 6-Feb-17: Waiting upon REV2 of WPL & CWP 2187. 22-Feb-17: Waiting upon REV2 of WPL & CWP 2187. New revised TCDs show dates of 28-Feb-2017. 28-Feb-17: TCDs for the WPLs and CWP have been moved. CWP 2187 TCD 8-Mar. NK38-WPL-34200-0596707 & NK38-WPL-34200-0596901 TCD 15-Mar.

Outage Window	Window Description
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
085	085 - AL Closed, Shielding Removal & Pressure Test

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12400	Potential critical path schedule delay during Unit 2 bulkhead removal resulting from overlap with D1941 outage [Window 88]	[Execution Phase] Event: Potential critical path schedule delay during Unit 2 bulkhead removal resulting from overlap with D1941 outage Cause:There is a schedule risk during the removal of the bulkheads on Unit 2 due to overlap with the D1941 outage. Fueling of Unit 3 will require irradiated fuel to traverse past unit 2 or 4. Impact: Once the bulkhead shielding is removed there will be a delay to one of the outages when the vault is vacated to allow for irradiated fuel movement.	1	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Mitigate	31-May-19	2	1	2	4	2	1	1	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**						
			8276	Not Started	Islanding scheduler to track D1941 if on track or delayed	Islanding scheduler to track D1941 if on track or delayed.		Bert Boston	Mehri Molanaie	30-Nov-18							
			Outage Window		**Window Description**												
			088		088 - Bulkhead Removal												
14417	Fuelling machine might interfere with the bulkhead panels [Window 023]	Event: Fueling machine may not have enough clearance when the temporary bulkheads panels would be installed and comes in contact when traversing under unit. Designed clearance is minimal. Cause: Configuration management issues, incorrect installation/fabrication or FME issues. Impact: Significant damage to FM.		Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	15-Apr-17	1	3	4	4	1	3	4	4
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11950	Containment Isolation work in the Fuel Handling duct could increase the critical path schedule and lead to cost overruns due to fueling requirements [Window 23, 88]	[Execution Phase] Event:The critical path isolation of the refurb unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. The frequency/availability and duration of no-fueling windows is determined by operating unit zone levels, trolley reliability and required trolley maintenance. Cause: Reasons for no fueling windows not occurring as planned could include unit zone conditions and trolley reliability. The JV planning basis is that any work below the 100m elevation 87% efficient for U2 BH install and drops to 50% for U2 removal and all other work on subsequent unit. This risk documents delay above and beyond the JV planning basis. Impact:If no fueling windows are shortened or do not occur per plan, critical path schedule delays will result as well as cost overruns due to crew standby time. This risk is to identify project level impacts. Program risk #685 is to identify impact at the program level (i.e. critical path that affects all of NR)*QUAD CHART RISK*	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	1	3	3	1	1	3	3
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			088		088 - Bulkhead Removal												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11993	Containment boundary calandria seal may fail during interspace pressure test during NR outage	[Execution Phase] Event: Containment boundary calandria seal may fail during interspace pressure test during NR outage. Risk may not pass initial testing. Cause:Seal degradation overtime and Units 2 and 3 were exposed to a vault pressure test after initial installation. Impact: significant scheduling impact on critical path if seal needs to be replaced. Note, based on knowledge gained during seal testing during previous outages, seal would have to catastrophically fail.	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	01-Jan-20	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14946	Issues with Bulkhead installation may occur due to mis-matched dimensions/as found conidities leading to critical path delays [Window 023].	Event: Bolt holes on BH panels may not line up with support holes/ as found conditions may prevent vertical and horizontal bulkhead installation. Cause: Errors in BH machining/improper installation may lead to hole misalignment. As the work is FOAK/FIAW, there are large possibilities of discovery work that can prevent execution of work. Impact: Critical path delays.	4	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	3	1	3	1	3	1	3
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14847	Bulkhead panels may be damaged during CWP execution [Window 023].	Event: The Bulkhead panels may be damaged during transportation. Cause: Improper lifting/loading of BH panels Impact: Critical path and cost impacts	1	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	3	3	3	1	3	3	3
			Outage Window		**Window Description**												
			023		023 - Install Bulkheads												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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11486	Inadequate Bulkhead shielding may result in work stoppages at the vault during station fuelling operations [Window 025]	[Execution Phase] Event:Shielding may not provide adequate protection during fuelling operations resulting in work stoppages. Cause: Cause can be due to design deficiency, manufacturing deficiency, and error in modeling. Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Accept	14-Apr-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			025		025 - Install Bulkhead Shielding												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Unit Islanding - 73463																	
12391	Critical Path extension in refurb unit due to inadequate Vault Vapour Recovery System performance. [Window 137]	Event: Delays to Containment Pressure tests to commission the Bulkhead due to high vault humidity. Cause: The pressure tests require low vault humidity which is obtained through efficient operation of the Vault Vapour Recovery System (VVRS). A pre-req project is being executed to address inadequate performance of the VVRS. This also impacts the time required to reduce tritium to allow both airlock doors open. Current unit Vault Vapour Recovery System reliability and efficiency levels are low which is currently acceptable because a common containment structure provides Vault Vapour Recovery Systemredundancy from other units. Installation of the containment Bulkhead will eliminate the redundancy for the Refurb unit and reduce the redundancy for the operating station. Impact: Inadequate performance of the refurb unit Vault Vapour Recovery System will potentially delay obtaining the required humidity levels for testing and delay critical path	3	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	3	1	2	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			2172	In Progress	Develop plan for optimizing efficiency and reliability of Vault Vapour Recovery System in U2	Monitor station progress on Vault Vapour Recovery repairs. If repairs are not planned to be completed by then refurb will develop an action plan for assessing and taking necessary actions to ensureoptimum efficiency and reliability of Vault Vapour Recovery Systemin U2	Bert Boston	Sarah Elliott	28-Apr-17	Systems Available for refurb initiative in progress. There are currently no significant reliability issues with the VVRS system that will impact refurb. No requirement to take action at this point Continue to monitor until the start of NR -Action YCD pushed to end of March to see VVRS performance during execution of W137.							
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11449	Failure of Containment Boundary pressure tests resulting in critical path delays [Window 024, 085]	[Execution Phase] Event: Failure of Containment Boundary pressure tests resulting in critical path delays Cause: The specified leak rates may not be achieved which would require the leak to be found, addressed, and the pressure test repeated. Possible failure mods are as follows: Portions of the U2 and U3 new Temporary Containment Boundary have never been part of the containment boundary and therefore have never been pressure tested. This includes the calandria seal, SDC room wall, and vertical BH. This new boundary may contain leak paths in the form of concrete cracks, leaks around EP's or weld cracks. There may be unusual system alignments during the pressure tests which may inadvertently introduce leak paths or damage systems which would in turn leak. Unit 2 and Unit 3 permanent bulkheads could fail the commissioning pressure test. Leaking closure plugs may cause leakage into PHT or increase humidity levels in the vault causing inaccurate readings or allow air into the PHT system which would indicate a leak. leakage of new BH panels Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	14-Apr-17	2	1	2	4	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8857	In Progress	Ensure contingency materials are ordered for concrete repairs during pressure test	Failure of the pressure test for the Temporary Containment Boundary may occur due to damage on the Concrete walls within the vault. To ensure minimal delays for the concrete wall repair, all contingency materials will be ordered and onsite ahead of the pressure test.	Bert Boston	Mehri Molanaie	07-Mar-17	21-Oct-16: Grout ordered, contingency plan being built into CWP. 21-Nov-16: Action on track 14-Dec-16: New TCD for materials. 19-Dec-16: Follow up e-mail sent to JV. PO is being placed to procure contingency materials. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: OPG to follow up with JV procurement. 6-Feb-17: Material ordered but not onsite. 28-Feb-17: Material delivery has been estimated for 7-Mar-17.							

ONTARIO POWER GENERATION

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21-Oct-16:
JV will be creating a contingency planning and associated WO for any repairs identified as immediately needed if there is a pressure test failure, test abortion and retesting is required. The WO instructions is to include specific instructions/support required from JV Civil Engineering and/or Resident Engineering to procedurally instruct how the repair is to be performed. JV will be procuring materials to support contingency repairs.
The contingency WO will align and referenced in CWP 2187 - UNIT 2 TEMPORARY CONTAINMENT BOUNDARY COMMISSIONING PRESSURE TEST AND LEAK SEARCHING which currently provides detailed work instructions for any contingency repairs that are required.
Continue to monitor to see if WO & WO tasks are correctly integrated into CWP.
21-Nov-16: Action on track.
19-Dec-16: Follow up e-mail sent to JV. JV assessing to update WO with contingency tasks. TCD to be provide by JV (Shawn Thompson).
6-Jan-17: Decision matrix created, JV to finalize and issue.
18-Jan-17: P6 scheduling remaining from JV. TCD 28th Jan
6-Feb-17: Waiting upon REV2 of WPL & CWP 2187.
22-Feb-17: Waiting upon REV2 of WPL & CWP 2187. New revised TCDs show dates of 28-Feb-2017.
28-Feb-17: TCDs for the WPLs and CWP have been moved. CWP 2187 TCD 8-Mar. NK38-WPL-34200-0596707 & NK38-WPL-34200-0596901 TCD 15-Mar.

Outage Window	Window Description
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
085	085 - AL Closed, Shielding Removal & Pressure Test

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11950	Containment Isolation work in the Fuel Handling duct could increase the critical path schedule and lead to cost overruns due to fueling requirements [Window 23, 88]	[Execution Phase] Event:The critical path isolation of the refurb unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. The frequency/availability and duration of no-fueling windows is determined by operating unit zone levels, trolley reliability and required trolley maintenance. Cause: Reasons for no fueling windows not occurring as planned could include unit zone conditions and trolley reliability. The JV planning basis is that any work below the 100m elevation 87% efficient for U2 BH install and drops to 50% for U2 removal and all other work on subsequent unit. This risk documents delay above and beyond the JV planning basis. Impact:If no fueling windows are shortened or do not occur per plan, critical path schedule delays will result as well as cost overruns due to crew standby time. This risk is to identify project level impacts. Program risk #685 is to identify impact at the program level (i.e. critical path that affects all of NR)*QUAD CHART RISK*	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	1	3	3	1	1	3	3

Outage Window	Window Description
023	023 - Install Bulkheads
088	088 - Bulkhead Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
11993	Containment boundary calandria seal may fail during interspace pressure test during NR outage	[Execution Phase] Event: Containment boundary calandria seal may fail during interspace pressure test during NR outage. Risk may not pass initial testing. Cause:Seal degradation overtime and Units 2 and 3 were exposed to a vault pressure test after initial installation. Impact: significant scheduling impact on critical path if seal needs to be replaced. Note, based on knowledge gained during seal testing during previous outages, seal would have to catastrophically fail.	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	01-Jan-20	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11486	Inadequate Bulkhead shielding may result in work stoppages at the vault during station fuelling operations [Window 025]	[Execution Phase] Event:Shielding may not provide adequate protection during fuelling operations resulting in work stoppages. Cause: Cause can be due to design deficiency, manufacturing deficiency, and error in modeling. Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Accept	14-Apr-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			025		025 - Install Bulkhead Shielding												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
Project: Unit Islanding - 73464																	
12391	Critical Path extension in refurb unit due to inadequate Vault Vapour Recovery System performance. [Window 137]	Event: Delays to Containment Pressure tests to commission the Bulkhead due to high vault humidity. Cause: The pressure tests require low vault humidity which is obtained through efficient operation of the Vault Vapour Recovery System (VVRS). A pre-req project is being executed to address inadequate performance of the VVRS. This also impacts the time required to reduce tritium to allow both airlock doors open. Current unit Vault Vapour Recovery System reliability and efficiency levels are low which is currently acceptable because a common containment structure provides Vault Vapour Recovery Systemredundancy from other units. Installation of the containment Bulkhead will eliminate the redundancy for the Refurb unit and reduce the redundancy for the operating station. Impact: Inadequate performance of the refurb unit Vault Vapour Recovery System will potentially delay obtaining the required humidity levels for testing and delay critical path	3	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	3	1	2	6	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			2172	In Progress	Develop plan for optimizing efficiency and reliability of Vault Vapour Recovery System in U2	Monitor station progress on Vault Vapour Recovery repairs. If repairs are not planned to be completed by then refurb will develop an action plan for assessing and taking necessary actions to ensureoptimum efficiency and reliability of Vault Vapour Recovery Systemin U2	Bert Boston	Sarah Elliott	28-Apr-17	Systems Available for refurb initiative in progress. There are currently no significant reliability issues with the VVRS system that will impact refurb. No requirement to take action at this point Continue to monitor until the start of NR -Action YCD pushed to end of March to see VVRS performance during execution of W137.							
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
11449	Failure of Containment Boundary pressure tests resulting in critical path delays [Window 024, 085]	[Execution Phase] Event: Failure of Containment Boundary pressure tests resulting in critical path delays Cause: The specified leak rates may not be achieved which would require the leak to be found, addressed, and the pressure test repeated. Possible failure mods are as follows: Portions of the U2 and U3 new Temporary Containment Boundary have never been part of the containment boundary and therefore have never been pressure tested. This includes the calandria seal, SDC room wall, and vertical BH. This new boundary may contain leak paths in the form of concrete cracks, leaks around EP's or weld cracks. There may be unusual system alignments during the pressure tests which may inadvertently introduce leak paths or damage systems which would in turn leak. Unit 2 and Unit 3 permanent bulkheads could fail the commissioning pressure test. Leaking closure plugs may cause leakage into PHT or increase humidity levels in the vault causing inaccurate readings or allow air into the PHT system which would indicate a leak. leakage of new BH panels Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	14-Apr-17	2	1	2	4	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8857	In Progress	Ensure contingency materials are ordered for concrete repairs during pressure test	Failure of the pressure test for the Temporary Containment Boundary may occur due to damage on the Concrete walls within the vault. To ensure minimal delays for the concrete wall repair, all contingency materials will be ordered and onsite ahead of the pressure test.	Bert Boston	Mehri Molanaie	07-Mar-17	21-Oct-16: Grout ordered, contingency plan being built into CWP. 21-Nov-16: Action on track 14-Dec-16: New TCD for materials. 19-Dec-16: Follow up e-mail sent to JV. PO is being placed to procure contingency materials. TCD to be provide by JV (Shawn Thompson). 6-Jan-17: OPG to follow up with JV procurement. 6-Feb-17: Material ordered but not onsite. 28-Feb-17: Material delivery has been estimated for 7-Mar-17.							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
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21-Oct-16:
JV will be creating a contingency planning and associated WO for any repairs identified as immediately needed if there is a pressure test failure, test abortion and retesting is required. The WO instructions is to include specific instructions/support required from JV Civil Engineering and/or Resident Engineering to procedurally instruct how the repair is to be performed. JV will be procuring materials to support contingency repairs.
The contingency WO will align and referenced in CWP 2187 - UNIT 2 TEMPORARY CONTAINMENT BOUNDARY COMMISSIONING PRESSURE TEST AND LEAK SEARCHING which currently provides detailed work instructions for any contingency repairs that are required.
Continue to monitor to see if WO & WO tasks are correctly integrated into CWP.
21-Nov-16: Action on track.
19-Dec-16: Follow up e-mail sent to JV. JV assessing to update WO with contingency tasks. TCD to be provide by JV (Shawn Thompson).
6-Jan-17: Decision matrix created, JV to finalize and issue.
18-Jan-17: P6 scheduling remaining from JV. TCD 28th Jan
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22-Feb-17: Waiting upon REV2 of WPL & CWP 2187. New revised TCDs show dates of 28-Feb-2017.
28-Feb-17: TCDs for the WPLs and CWP have been moved. CWP 2187 TCD 8-Mar. NK38-WPL-34200-0596707 & NK38-WPL-34200-0596901 TCD 15-Mar.

Outage Window	Window Description
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
085	085 - AL Closed, Shielding Removal & Pressure Test

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
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11950	Containment Isolation work in the Fuel Handling duct could increase the critical path schedule and lead to cost overruns due to fueling requirements [Window 23, 88]	[Execution Phase] Event:The critical path isolation of the refurb unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. The frequency/availability and duration of no-fueling windows is determined by operating unit zone levels, trolley reliability and required trolley maintenance. Cause: Reasons for no fueling windows not occurring as planned could include unit zone conditions and trolley reliability. The JV planning basis is that any work below the 100m elevation 87% efficient for U2 BH install and drops to 50% for U2 removal and all other work on subsequent unit. This risk documents delay above and beyond the JV planning basis. Impact:If no fueling windows are shortened or do not occur per plan, critical path schedule delays will result as well as cost overruns due to crew standby time. This risk is to identify project level impacts. Program risk #685 is to identify impact at the program level (i.e. critical path that affects all of NR)*QUAD CHART RISK*	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	24-Mar-17	1	1	3	3	1	1	3	3

Outage Window	Window Description
023	023 - Install Bulkheads
088	088 - Bulkhead Removal

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
11993	Containment boundary calandria seal may fail during interspace pressure test during NR outage	[Execution Phase] Event: Containment boundary calandria seal may fail during interspace pressure test during NR outage. Risk may not pass initial testing. Cause:Seal degradation overtime and Units 2 and 3 were exposed to a vault pressure test after initial installation. Impact: significant scheduling impact on critical path if seal needs to be replaced. Note, based on knowledge gained during seal testing during previous outages, seal would have to catastrophically fail.	2	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Monitor	01-Jan-20	1	2	3	3	1	2	3	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
11486	Inadequate Bulkhead shielding may result in work stoppages at the vault during station fuelling operations [Window 025]	[Execution Phase] Event:Shielding may not provide adequate protection during fuelling operations resulting in work stoppages. Cause: Cause can be due to design deficiency, manufacturing deficiency, and error in modeling. Impact: Schedule delays	3	Active	Bert Boston	Mehri Molanaie	17-Feb-17	Accept	14-Apr-17	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**												
			025		025 - Install Bulkhead Shielding												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Project: Unit Islanding - 73466

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13501	Risk that Barriers may not be able to be reused for subsequent outages. [No Window Related]	Event: Risk that Barriers may not be able to be reused for subsequent outages. Cause: More barriers than planned may be worn out, or damaged, and need to be replaced. Impact: This will lead to increased material cost and possibly schedule delay.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Jan-20	4	1	2	8	4	1	1	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8514	Not Started	Review of barriers material usage for Unit 1.	A specific review of barriers materials usage is needed once Unit 1 refurbishment is well under way/complete.	Bert Boston	Sarah Elliott	31-Jan-20								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
11623	The construction island barriers may need to be adjusted for individual projects [Window 500]	Event:The Refurb Island barriers (which typically reside along the unit boundaries) have been designed to accommodate many lay down areas and work areas. Cause: Late identification of new areas may mean the barriers need to be adjusted. Impact: This will result in costs associated with Engineering Change revisions. If barriers can't be moved quickly, then EPC delay claims may also result.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Monitor	15-Jun-19	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			500		500 - Installation of Barrier and Fencing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13502	Risk that we may have to switch back to more robust fencing leading to engineering rework, higher material cost, and schedule delays. [No Window Related]	Event: During Refurb, it may be determined that more robust barriers are needed to separate the construction Island from the operating units. Cause: Regulator requirements or internal project requirements. Impact: This will lead to engineering rework, additional material costs, and schedule delays.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Aug-17	1	2	2	2	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8273	In Progress	Evaluate human performance events	Evaluate human performance events where wrong unit identification was a factor. Determine if more robust fencing is needed.	Bert Boston	Sarah Elliott	31-Jul-17								
			Outage Window		**Window Description**												
			000		000 – No Window Related												

Project: Unit Islanding - 73467

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13501	Risk that Barriers may not be able to be reused for subsequent outages. [No Window Related]	Event: Risk that Barriers may not be able to be reused for subsequent outages. Cause: More barriers than planned may be worn out, or damaged, and need to be replaced. Impact: This will lead to increased material cost and possibly schedule delay.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Jan-20	4	1	2	8	4	1	1	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8514	Not Started	Review of barriers material usage for Unit 1.	A specific review of barriers materials usage is needed once Unit 1 refurbishment is well under way/complete.	Bert Boston	Sarah Elliott	31-Jan-20								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
11623	The construction island barriers may need to be adjusted for individual projects [Window 500]	Event:The Refurb Island barriers (which typically reside along the unit boundaries) have been designed to accommodate many lay down areas and work areas. Cause: Late identification of new areas may mean the barriers need to be adjusted. Impact: This will result in costs associated with Engineering Change revisions. If barriers can't be moved quickly, then EPC delay claims may also result.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Monitor	15-Jun-19	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			500		500 - Installation of Barrier and Fencing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13502	Risk that we may have to switch back to more robust fencing leading to engineering rework, higher material cost, and schedule delays. [No Window Related]	Event: During Refurb, it may be determined that more robust barriers are needed to separate the construction Island from the operating units. Cause: Regulator requirements or internal project requirements. Impact: This will lead to engineering rework, additional material costs, and schedule delays.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Aug-17	1	2	2	2	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8273	In Progress	Evaluate human performance events	Evaluate human performance events where wrong unit identification was a factor. Determine if more robust fencing is needed.		Bert Boston	Sarah Elliott	31-Jul-17							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
Project: Unit Islanding - 73468																	
13501	Risk that Barriers may not be able to be reused for subsequent outages. [No Window Related]	Event: Risk that Barriers may not be able to be reused for subsequent outages. Cause: More barriers than planned may be worn out, or damaged, and need to be replaced. Impact: This will lead to increased material cost and possibly schedule delay.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Jan-20	4	1	2	8	4	1	1	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8514	Not Started	Review of barriers material usage for Unit 1.	A specific review of barriers materials usage is needed once Unit 1 refurbishment is well under way/complete.		Bert Boston	Sarah Elliott	31-Jan-20							
			Outage Window		**Window Description**												
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11623	The construction island barriers may need to be adjusted for individual projects [Window 500]	Event:The Refurb Island barriers (which typically reside along the unit boundaries) have been designed to accommodate many lay down areas and work areas. Cause: Late identification of new areas may mean the barriers need to be adjusted. Impact: This will result in costs associated with Engineering Change revisions. If barriers can't be moved quickly, then EPC delay claims may also result.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Monitor	15-Jun-19	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			500		500 - Installation of Barrier and Fencing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13500	Risk that design assumptions for barrier configurations are different when two units are overlapped for refurbishment [No Window Related]	Event: Design assessments performed for the design of the NR barrier projects may be impacted by the configuration with two units overlapped in refurb. E.g. fire safety assessments, NS assessments, etc. Cause: Improper assessment and assumptions made when the two units are overlapped. Impact: This will lead to additional engineering work and schedule delays.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	30-Jun-22	2	1	1	2	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8271	Not Started	Create contingency plan for unit overlap	Create a contingency plan for possible issues, or conduct an assessment.		Bert Boston	Sarah Elliott	01-Jan-18							
			8280	Not Started	Review transitions report	Review transitions report and Unit 1 design prior to the start of Unit 3 work.		Bert Boston	Sarah Elliott	22-Jun-22							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
13502	Risk that we may have to switch back to more robust fencing leading to engineering rework, higher material cost, and schedule delays. [No Window Related]	Event: During Refurb, it may be determined that more robust barriers are needed to separate the construction Island from the operating units. Cause: Regulator requirements or internal project requirements. Impact: This will lead to engineering rework, additional material costs, and schedule delays.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Aug-17	1	2	2	2	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
			8273	In Progress	Evaluate human performance events	Evaluate human performance events where wrong unit identification was a factor. Determine if more robust fencing is needed.		Bert Boston	Sarah Elliott	31-Jul-17							
			Outage Window		**Window Description**												
			000		000 – No Window Related												
Project: Unit Islanding - 73469																	
13501	Risk that Barriers may not be able to be reused for subsequent outages. [No Window Related]	Event: Risk that Barriers may not be able to be reused for subsequent outages. Cause: More barriers than planned may be worn out, or damaged, and need to be replaced. Impact: This will lead to increased material cost and possibly schedule delay.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Jan-20	4	1	2	8	4	1	1	4
			Action#	**Status**	**Action Title**	**Action Description**		**Owner**	**Delegate**	**Due Date**	**Comments**							
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			Outage Window		**Window Description**												
			000		000 – No Window Related												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
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			Outage Window		**Window Description**												
			500		500 - Installation of Barrier and Fencing												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13500	Risk that design assumptions for barrier configurations are different when two units are overlapped for refurbishment [No Window Related]	Event: Design assessments performed for the design of the NR barrier projects may be impacted by the configuration with two units overlapped in refurb. E.g. fire safety assessments, NS assessments, etc. Cause: Improper assessment and assumptions made when the two units are overlapped. Impact: This will lead to additional engineering work and schedule delays.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	30-Jun-22	2	1	1	2	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
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13502	Risk that we may have to switch back to more robust fencing leading to engineering rework, higher material cost, and schedule delays. [No Window Related]	Event: During Refurb, it may be determined that more robust barriers are needed to separate the construction Island from the operating units. Cause: Regulator requirements or internal project requirements. Impact: This will lead to engineering rework, additional material costs, and schedule delays.	1	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Aug-17	1	2	2	2	1	2	1	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8273	In Progress	Evaluate human performance events	Evaluate human performance events where wrong unit identification was a factor. Determine if more robust fencing is needed.	Bert Boston	Sarah Elliott	31-Jul-17								
			Outage Window		**Window Description**												
			000		000 – No Window Related												
Project: Unit Islanding - 73490																	
13528	While anchoring the airlock restraint into the floor a bolt may hit burried piping or cable [Window 137]	Event: While anchoring the airlock restraint into the floor a bolt may hit burried piping or cable. Cause: Floor scans didn't pick up piping and/or cables. Impact: When the bolts to restrain the airlock are drilled into the concrete they may hit cables or piping that are embedded in the concrete which will lead to schedule delays and cost impacts as the work will be stood down and damage assessed.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	1	1	3	3	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8274	In Progress	Have drill cards ready	Airlocks restraints will be anchored down. Get field engineering to perform floor scans to see if any possible interferences. Design engineering to re-evaluate if interferences are identified.	Bert Boston	Sarah Elliott	31-Mar-17	Proactively have drill card. Nov 2 2016: OPG MTL to get WO TSK ready & conduct walkdowns of drill areas. 6-Jan-17: Drill cards are with FLM. TCD 15-Feb. 6-Feb-17: Drill Cards ready. Walkdowns to be performed EOW. 1-Mar-17: Scans to be completed next week.								
			Outage Window		**Window Description**												
			137		137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)												
Project: Unit Islanding - 73492																	
13528	While anchoring the airlock restraint into the floor a bolt may hit burried piping or cable [Window 137]	Event: While anchoring the airlock restraint into the floor a bolt may hit burried piping or cable. Cause: Floor scans didn't pick up piping and/or cables. Impact: When the bolts to restrain the airlock are drilled into the concrete they may hit cables or piping that are embedded in the concrete which will lead to schedule delays and cost impacts as the work will be stood down and damage assessed.	2	Active	Bert Boston	Sarah Elliott	01-Mar-17	Mitigate	31-Mar-17	1	1	3	3	1	1	2	2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			8274	In Progress	Have drill cards ready	Airlocks restraints will be anchored down. Get field engineering to perform floor scans to see if any possible interferences. Design engineering to re-evaluate if interferences are identified.	Bert Boston	Sarah Elliott	31-Mar-17	Proactively have drill card. Nov 2 2016: OPG MTL to get WO TSK ready & conduct walkdowns of drill areas. 6-Jan-17: Drill cards are with FLM. TCD 15-Feb. 6-Feb-17: Drill Cards ready. Walkdowns to be performed EOW. 1-Mar-17: Scans to be completed next week.								

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13528	While anchoring the airlock restraint into the floor a bolt may hit burried	Event: While anchoring the airlock restraint into the floor a bolt may hit burried piping or cable. Cause: Floor scans didn't pick up piping and/or cables. Impact: When the bolts to restrain th	**Outage Window**	**Window Description**													
			137	137 - Final Commissioning (VVRS Ph-I, AL&TCD Logic Mods, BU Logic Mod Ph-II)													

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
715	Funding for Unexpected Legal Costs	Event: Over the duration of refurbishment, additional legal support may be required to support disputes and/or change management Cause: Insufficient funding to deal with additional and/or emergent legal support Impacts: May lead to delays in legal clarifications, resolution of items and unnecessary litigation	1	Active	Riyaz Habib	Garry Lam	13-Feb-17	Monitor	31-Dec-25	3	2	1	6	3	2	1	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
714	Potential Contract Management Function Resources Required for future Master Services Contract(s) or Replacement Contracts	Event: Limited contract management support for future MSA's (OSS replacement contracts, DESA, NSASA, Construction, etc). Cause: Insufficient contract management resources have been budgeted beyond 2016. Impact: There may be a lack of alignment during the initial phase of future MSA contracts, and significant savings will not be achieved through the identification and correction of inefficiencies and implementation of issue resolution processes.	1	Active	Riyaz Habib	Garry Lam	13-Feb-17	Monitor	31-Dec-27	3	1	1	3	3	1	1	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
496	CNSC does not grant timely approval for unit return to service post refurbishment	The risk is that CNSC does not grant the necessary approvals for clearing of restart regulatory hold points in a timely manner thus impacting the return to service schedule.	1	Active	David Train	Paul Dunn	22-Feb-17	Avoid	31-Oct-19	1	3	1	3	1	3	1	3
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
673	Licensing Fees Higher than Release 4c Budget Estimate	The risk is that the licensing fees are expected to be higher than projected in the 4c release estimate. The release estimate uses the 2014 CNSC projected costs for Darlington, and for Refurbishment, and assumes future increases over the life of the project remain constant at the 1.5% year over year increase projected for CNSC fiscal 2015/2016 and 2016/2017. The 2015 CNSC projected costs for Darlington and for refurbishment are due in early May. This risk will be updated at that time as required. April	1	Active	David Train	Paul Dunn	22-Feb-17	Accept	30-Jun-15	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
750	The risk is that OPG may not be able to complete a number of IIP commitments as per schedule	The risk is that OPG may not be able to complete a number of IIP commitments by the IIP committed date A missed IIP date is a violation of the Darlington Operating License Which may result in negative regulatory interface. the IIP commitments are reviewed on a regular basis with each of the IIP task owners. Metrics are in place to track completion and the IIP Change Control Process is implemented if an IIP can not meet its TCS (i.e change requests were submitted for EPG3 and CFVS modification and approved by CNSC). Note that CFVS modification installation milestone for IIP-EA-009 was missed and new extension request has been submitted to CNSC.	1	Active	Nienke Smith		27-Feb-17	Mitigate	31-Mar-26	4	1	3	12	3	2	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
797	Vendor technical proficiency and less than adequate adherence to design governance may lead to unforeseen issues during design implementation/execution, leading to rework, cost overruns and schedule delays.	Event: Failure to follow processes as written in design governance and failure to rigorously complete all required steps may not allow the full benefit of the robustness of the ECC design process to be realized. Cause: The many steps in the process are typically built upon previously identified process short-comings, and failure to rigorously execute each step may lead to re-work, for example failure to rigorously complete system heath/component health report research, failure to complete an effective COMs meeting, failure to complete a meaningful OPEX search, and failure to identify and address issues in the Issue Tracking file (ITF) may lead to an inadequate design. Impact: The inadequate design may not be fully released until the point of installation/execution, at which time rework, cost overruns or schedule delays may occur.	4	Active	Emily Tarle	Rajeev Leekha	27-Feb-17	Mitigate	31-Mar-17	2	2	4	8	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			6754	In Progress	INPO Design Engineer Desk Top Guide – Develop NR similar document.	INPO Design Engineer Desk Top Guide – Develop NR similar document.	Emily Tarle	Nienke Smith	31-Mar-17	24MAY2016 - Review held as planned, transitioned ownership to Emily Tarle and extended to July 20th. 11MAY2016 - Guide in progress with Quality Engineering. Review of the product scheduled for 17MAY2016. 21JUL2016 - Much of this guidance is already available in Nuclear or Refurbishment processes and instructions, however this will be reviewed with Fleet Design Engineering for generation of a separate guide or to address gaps (E. Tarle) 01DEC2016 - It is determined that a separate guide for NR Engineering is not required, however the action will be left open and considered in conjunction with other actions supporting overall risk item 797 "Vendor Technical Proficiency".				
			6759	In Progress	Propose and develop a gated challenge process for the replicated design process.	Propose and develop a gated challenge process for the replicated design process. This action will produce an updated guide document for Nuclear Refurbishment.	Raza Zaidi	Joshua Guin	31-Mar-17	25JAN2017 - Additional organizational reviews identified. TCD updated. 17JAN2017 - Design Replication Guide D-GUID-09701-10043 R000 has been drafted to facilitate a consistent approach to replication for subsequent unit designs. It has been recommended by the NP-MSRB and is undergoing final review and signoff by stakeholders. Date updated to align with RMO Action #6768 (also note that N-2016-25397 due 31-Mar-2017 is also associated with the issuance of this guide). 16AUG2016 - This work is currently being contracted out to a vendor and is expected to be completed by 31 December 2016. 29JUL2016 - Tabletop review has been done with OSS and improvement identified will be incorporated into the updated guide. 04Jul2016 - expectations will be finalized in July and captured in a briefing card/governance updates (as required) 24May2016 - owner transition to Emily Tarle, TCD extended to June 30, 2016. 11MAY2016 - Work is underway with Quality Engineering for a replication instruction and gates. To be reviewed by May 17th.				

792	Vendor technical proficiency and less than adequate adherence to design governance may lead to unforeseen issues during design implementation/execution, leading to rework, cost overruns and schedule delays.	Event: Failure to follow processes as written in design governance and failure to rigorously complete all required steps may not allow the full benefit of the robustness of the ECC design process to be realized. Cause: The many steps in the process are typically built upon previously identified process short-comings, and failure to rigorously execute each step may lead to re-work, for example failure to rigorously complete system heath/component health report research, failure to complete an effective COMs meeting, failure to complete a meaningful OPEX search, and failure to identify and address issues in the Issue Tracking file (ITF) may lead to an inadequate design. Impact: The inadequate design may not be fully released until the point of installation/execution, at which time rework, cost overruns or schedule delays may occur.	6766	In Progress	Conduct a self assessment across all organizational boundaries including contractor agencies to determine what improvements are needed to achieve a true collaborative engineering approach.	Conduct a self assessment across all organizational boundaries including contractor agencies to determine what improvements are needed to achieve a true collaborative engineering approach.	Emily Tarle	Nienke Smith	31-Mar-17	11may2016 - Work has begun with Quality Engineering to assist on the SA. 21JUL2016 - Self assessment to be conducted in Q3 2016 and include input from working level staff (Design Engineers, Section Managers). Timing is to ensure lessons learned and opportunities for improvement are applied to replication efforts (E. Tarle)
			6768	In Progress	Develop rollout and deliver use of the full spectrum of risk levels afforded by the risk-based ECC process.	Develop rollout and deliver use of the full spectrum of risk levels afforded by the risk-based ECC process.	Emily Tarle	Raza Zaidi	31-Mar-17	21JUL2016 - This will be included in the Replication Guide for Refurbishment (E. Tarle) 1NOV2016 - Replication Guide will be issued by January 20, 2017 (N.Smith) 25JAN2017 - Final Draft of Replication Guide is completed. Undergoing further organizational reviews. TCD updated.
			6782	In Progress	Proficiency	Proficiency The action is to formalize the requirement for monitoring and managing OPG and Vendor proficiencies by developing and implementing a report card. Reference AR 28184215-04, 5, 6.	Nienke Smith	Saad Malakhail	13-Mar-17	Proficiency report cards have been created to measures INPO's proficiency building blocks (list below). Gaps in proficiency will be determined by evaluating vendors and OPG personnel against the scorecards. Mitigating action 6748 (references AR 28184215-04) is to develop and implement the report card for OPG and each of OPG's primary vendor: General Electric, SNC, Sargent Lundy, RCMT, AMEC NSS, Tetra Tech, Worley Parsons and Areva. INPO Proficiency Building Blocks 1) Education 2) Skills Training 3) Repetition with feedback 4) Experience in a variety of situations 5) Timeliness or currency of performance
			6784	In Progress	Follow up from COMS repast	Follow up from COMS REPAST. Reference: RF16-000663-SA - NR Engineering COMS Performance Analysis (REPAST)	Nienke Smith	Rahul Nandi	31-Mar-17	AR#28188301 – 01,02,03,04 has been created to track to completion the actions from the COMS Repast. AR 28188301-01/02 - Briefing card and Directive from SVP, Nuclear Projects has been issued and rolled out to all Project teams part of NR Engineering, NR Execution, P&M outlining COMS expectations - ACTION COMPLETE AR 28188301-04 - New COMS qualifications were developed by NR Training for all NR COMS Participants (QUAL 40263) and NR COMS Leaders (QUAL 40264). Communications sent out. Compliance date is March 31, 2017 - ACTION COMPLETE Other COMS Improvement Initiatives: 23 interactive COMS workshops were delivered successfully to folks all across Refurb and DNG station. 'COMS Champion' assigned to provide oversight on all NR COMS. Effectiveness reviews to be conducted by end of Q1, 2017 (tracked by A/R 28189981).
			9765	In Progress	Implement Oversight on Vendor Procurement of Material	Implement Oversight on Vendor Procurement of Material : Refurbishment Design Engineering performing in process and strategic oversight on vendor's material and service procurement.	Rajeev Leekha	Mahtab Khondaker	30-Jun-17	1. Strategic Oversight Completed at BWXT on Oct on Procurement of Spare Parts for Valve Program (BOP) 2. Self assessment # RF16-001900-SA in progress to monitor the Quality of MEL and BOM records done by EPC/ESMSA Vendor

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792	Vendor technical proficiency and less than adequate adherence to design governance may lead to unforeseen issues during design implementation/execution, leading to rework, cost overruns and schedule delays.	Event: Failure to follow processes as written in design governance and failure to rigorously complete all required steps may not allow the full benefit of the robustness of the ECC design process to be realized. Cause: The many steps in the process are typically built upon previously identified process short-comings, and failure to rigorously execute each step may lead to re-work, for example failure to rigorously complete system heath/component health report research, failure to complete an effective COMs meeting, failure to complete a meaningful OPEX search, and failure to identify and address issues in the Issue Tracking file (ITF) may lead to an inadequate design. Impact: The inadequate design may not be fully released until the point of installation/execution, at which time rework, cost overruns or schedule delays may occur.	9785	In Progress	Oversight of software qualifications and documentations	Implement Oversight of vendor compliance to software qualifications and documentations.	Rajeev Leekha	Bhaskar Pillarisetty	30-Jun-17	· Majority of refurbishment designs are mature and have had the benefit of OPG oversight and questioning attitude wrt to SQA. This approach has discovered SQA issues such as in AHS and the Fire system. Risks of additional findings are low. · Software audits have occurred on select projects to review software governance adherence. · CCD spoc has been involved in most of the large projects involving software, eg EPG3, T/G, SDC, PSVS, RFR, HWMB, which are following proper SQA processes. · ECC Design scoping checklist has been improved in section 2.7 – Software.
			Outage Window		**Window Description**					
			000		000 – No Window Related					
770	Discovery and Emergent work impacting Engineering	Event: It is expected that discovery work will be found during refurbishment outage and other IIP related work. During planning, inspections or detailed reviews of tasks it is possible that new work will be identified and will require Engineering support, including late identified temporary modifications for power, air and water supplies. Cause: The causes may be varied but centred around either inspections or re evaluation based on OPEX, failure of COMS or extent of condition, or new analysis. Impact: The impact of such emergent work could be further Engineering and Project support beyond what has been included in the budget.	1	Active	Emily Tarle	Rajeev Leekha	23-Feb-17	Mitigate	31-Mar-17	3 1 2 6 2 1 1 2
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**
			6776	In Progress	Engineering Work Management	Excellence in Engineering Work Management	Paul Ross	Alberto Castellanos	29-Sep-17	The following initiatives are under development: 1. Engineering Work Requests (EWR): Draft has been updated. See attached copy. To be issued after result from Pilot Project [attachment 2] 2. Confirm Source of Funding: CCF are being prepared. Example is the CCF-3352 New Scope Steam Door Modification In-House [Attachment 4] 3. Detailed Engineering Resource Histograms: Engineering Work Templates are going live. See attached Engineering Histogram by engineering crew codes [Attachment 5] 4. Engineering Visual Management Board (VMB): Engineering VMB is on draft. See attached picture of the mock-up [Attachment 3]. A meeting with the Sponsor was held and a plan forward was developed: Finalize Format & Data Hierarchy - November 04, 2016 to January 9, 2017. Pilot Project and Lessons Learned [System & Component] - January 09, 2017 to March 31, 2017. Rollout Final Process - June 30, 2017. Full Implementation - September 29, 2017.
			Outage Window		**Window Description**					
			000		000 – No Window Related					
937	Potential Cost Variance for Engineering Support to RFR/TG U3 Modifications	Event: There is not enough budget to support Engineering Oversight for RFR and TG for Unit 3 Cause: Budget under Engineering Oversight has been allocated to Seed Funds for In-House Replication Unit 3. At the time of the RQE, NR Engineering did not estimate for Seed Budget for Conceptual In-House Replication Unit 3 and RQE Submission is for Engineering Oversight only in the Engineering Change Control (ECC) Process done by EPC vendors and OPG Design. Replication for subsequent units was considered and budgeted by project bundles. Funds from Functional Engineering Support to Modifications would be utilized to pay for Conceptual Design. Impact: RFR and TG may not have Oversight Engineering Support as required which could lead to Execution delays.		Active	Emily Tarle	Rajeev Leekha	13-Feb-17	Monitor	29-Sep-17	3 1 2 6 3 1 2 6
			Outage Window		**Window Description**					
			000		000 – No Window Related					
			There are no Draft, Not Started, In Progress Actions associated with the risk.							

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952	Conduct Engineering Replication for U3_1_4 with OPG In-House Resources vs EPC	Event: Potential responsibility handoff issues regarding liability between Engineering, Procurement and Construction, and potential warranty issue for the defective work. Cause: Switch to OPG In House Engineering design and replication for U3_1_4, rather than using EPC model Impact: Cost and Schedule impact due to the extra handoff between OPG and Vendor comparing to EPC model, also OPG has to allocate contingency $ for defective work warranty.	2	Active	Emily Tarle	Raza Zaidi	24-Feb-17	Mitigate	30-Jun-17	2	1	3	6	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9847	In Progress	Define the handoff process between OPG In House Engineering and Vendor Procurment_Construction	Work with vendors to define a working process between Engineering and Procurement at vendor house. Also, ensure vendors are clear about the R&R related to Procurement and Construction in this OPG In-House design/engineering model.	Emily Tarle	Raza Zaidi	30-Jun-17	
9848	In Progress	Evlaute the cost impact assoicated with warrenty for def	Evaluate the extent and cost/schedule impact of potential impact due to defective design based on OPEX.	Emily Tarle	Raza Zaidi	30-Jun-17	

Outage Window	Window Description
000	000 – No Window Related

702	No enough engineering resources to support unit RTS, Commissioning and Close-Out	Event The risk is that there are not enough Systems and Components Engineering resources to support Execution readiness preparations, Commissioning, specialized areas, Physics, Fuel Handling and RTS Cause Inadequacy of appropriately trained staff in terms of numbers or money available to add FTES major milestone/delivery and the changes, in addition to incrementally higher resource demands during the overlap of subsequent outages Impact Delay the project execution.	1	Active	Paul Ross		23-Feb-17	Monitor	15-Oct-19	2	1	2	4	2	1	2	4

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

938	Continuity of the DNR HFE Program	Event: Potential lack of continuity of the DARLINGTON NUCLEAR REFURBISHMENT - INTEGRATED HUMA N FACTORS ENGINEERING PROGRAM PLAN (Ref. NK38-PLAN-06700-10001) which is a DN Refurbishment Project commitment to the CNSC. Cause: The OSS contract is scheduled to end without provision of continuity of HFE services under a new/alternate contract. Furthermore the scope of work document for the NOSS contract which is intended to provide continuity of DN Refurb Design Engineering oversight services in general, did not reference the applicable OPGN HFE governance describing the Human Factors Engineering process and required skill set (e.g. N-MAN-06700-10002). The NOSS selection criteria does not include specific consideration of, or credit for contractor HFE capabilities. Impact: Impact will be a lack of sufficient HFE resources to support the HFE activities identified in NK38-PLAN-06700-10001 Darlington Nuclear Refurbishment Integrated Human Factors Engineering Program Plan Section 2.5.2.2. See the reference document for the detailed role and list of tasks performed by the support services provider. In summary 2.5.2.2 states, " Under the direction of the OPG HFE Technical Expert integrated program SPOC, contractors will provide HFE services under OPGN's QA program in in accordance with OPG governance."		Active	Emily Tarle	Rajeev Leekha	16-Feb-17	Mitigate	31-Mar-17	3	1	1	3	1	1	1	1

Outage Window	Window Description
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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Program: Managed Systems Oversight - 10000																	
764	Vendor Performance and Inexperience Managing their CA Programs	EVENT: Vendor or OPG Poor Performance or poor vendor performance of the CA programs requiring additional oversight and OBU Resources CAUSE: Lack of capability, experience or time pressure or increased number of SCRs would be due to vendor's inability or inexperience in managing their corrective action programs to OPGs expectations IMPACT: Conduct additional oversight surveillances to identify and correct the problems and potential delays to field work. Also may be required to include all vendor adverse conditions in the OPG SCR database result in increase OPG administration cost. Further, poor vendor performance of the CA programs would result in recurring field issues and potential cost impacts and schedule delays to NR.	2	Active	Art Maki	Frank Dias	22-Feb-17	Monitor	31-Mar-17	3	1	2	6	3	1	2	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

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										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	3	Active	Johnathon Hash	Jeff Johansson	01-Feb-17	Mitigate	30-Dec-17	3	2	2	6	2	2	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5876	In Progress	Strategy for smear samples to determine radionuclide characterization for U2	a) Source Term Characterization · Section 2.2: Develop a strategy for taking smear samples for the purpose of source term characterization of Unit 2 when radioactive systems are opened up for refurbishment. Samples locations should include radioactive systems in Unit 2, RWPB, and Fuel Handling. Once samples are taken, they should be analyzed radio-chemically and the conclusions with respect to dose contributions from the AMEC report should be validated. Also calculate the beta-gamma: alpha ratio to confirm capability of WBM to indicate the presence of alpha emitting radionuclides in the body and continued use of pancake for both beta-gamma measurement and, by inference, alpha presence (as per N-INS-09071-10013).	Johnathon Hash	Joe Cicchini	01-Apr-17	(7 June Johansson): Initiate a search of the smears that were taken during 2015 VBO on Unit 2 and, if found, perform count on the smears and document results. (18 July; JJ) A search for the smears that were apparently taken on Unit 2 during the 2015 VBO was unsuccessful. Decision to initiate a new set of smears on Unit 4 during D1641 was made and smears were taken. Some of the areas/systems include in this smear program are (see attachment #1 below for more details): Floor under pressurizer x2 Floor near ball screw pit. 1 x east, 1 x west. Base of the boilers (around manway, bolts etc) 1 x east, 1 x west Mod room (051 or 052 on the valving) ESC (scrap pipe on platform) Reach inside (do not enter) feeder cabinet on 100 elev and smear walkway Top of Bleed condenser 107.5 elev SDC The smears were sent to the Chemistry lab for initial analysis. Lab results have been received, along with the smears. Additional alpha counting of the smears will be arranged with Kinectrics. (10 Aug; JJ) See email attachment #2 below for results of initial counts of the smears performed at the DN Chem Lab. Preparation in progress to send the smears to Kinectrics for alpha analysis. 25AUG2016 JC Smears being processed for shipment 14OCT2016 - Several smears have been processed and analyzed in previous outages this data will be used to anticipate and Unit 2 specific smears will be collected. (22 Nov; JJ) Additional smears were taken by DN RP in Unit 3 and Unit 4 in 2015/2016 outages respectively (see attachment #4 email). Together with similar legacy data (see attachment #3), attachment #4 data from U3 and 4 will be reviewed and analyzed to confirm the beta-gamma to alpha ratio to confirm that capability of WBMs to indicate the presence of Alpha emitting radionuclides, and the continued use of pancake meters for inference of alpha activity. (29 Dec; JJ) The above mentioned U3 & U4 smear analysis results will be reviewed by NRRP HPs to confirm beta-

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			5883	In Progress	Darlington Routine Radiation Surveys Instruction Modified to include Unit 2 Refurbishment	· Sect 4.1.1: Modify D-INS-09071-10012, Darlington Routine Radiation Surveys, to expand the routine alpha monitoring program for Unit 2 refurbishment. Moving due date to June 30 in order to capture recommendations from an external report for Hard to Detect Nuclide Monitoring. (7 June, JOHANSSON): moved due date to Aug 31, 2016.	Johnathon Hash	Jeff Johansson	03-Apr-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. (09 Nov; JJ) The highest potential for alpha presence may occur during RFR series work (EF cutting, PT cut, etc...). NRRP ALARA are preparing RFR series specific RPEGs that will include requirements for routine and non-routine alpha surveys/smears. The Darlington Routine Survey instruction will not be revised to incorporate such requirements as it is tracked under the RPEGS. (01 Feb; JJ) DRAFT Routine Survey RPEG has been issued for RP review (see attachment #1). This RPEG was discussed with the Field Section and an action was assigned to the Field Section to determine the level of effort/resources that will take to execute the proposed RPEG surveys.

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			5886	In Progress	Confirm Alpha Counting room for Refurbishment	· Sect 4.1.1: Confirm the availability of a facility for counting alpha contamination samples.	Johnathon Hash	Joe Cicchini	17-Mar-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. Explore Ryan's suggestion for NR-RP to own and operate the Darlington iSolo counting room, and offer to perform any Darlington RP smears and train their personnel as well. (July 14; JJ): In addition to securing a dedicated alpha counting room for Refurbishment work, it was suggested that HPD perform a QA program for the results by analyzing a fixed percentage of the smears collected and counted, and documenting the results in a QA report for audit purposes. This will be include in the PAS Sampling Policy that is tracked under Action #5880. 25AUG2016 JC - Refurb RP will be working with station RP to develop a smear counting strategy that will benefit both organizations. ***Initiator name changed from BurkeJ to CicchinJ due to Lan ID of burkej not being recognized.
			5887	In Progress	Confirm Monitoring Compliance with Alpha Contamination Limits	· Sect 4.2.1/4.3.1: Confirm through ongoing source term/alpha characterization of Unit 2 that the beta-gamma: alpha activity ratio is greater than 5. This will confirm that pancake and WBM are sufficient to confirm compliance with alpha contamination limits.	Johnathon Hash	Jeff Johansson	30-Sep-17	(7 June; JJ): Consider integrating this requirement into the NR-RP Routine Survey program. If appropriate, close this action to action # 5883. (18 July; JJ): Post June 13 meeting with HPD, a recommendation was made for NR-RP to explore other instruments for Alpha counting (other than iSolos). It was also suggested to have HPD Instrument group involved in this search. (03 Oct; JJ) The recommendation is to confirm through on-going source term and/or alpha characterization studies during refurbishment activities that the beta-gamma: alpha ratio activity is still > 5. Once RFR work commences in unit 2, smears of open system piping/equipment will be performed and analyzed to confirm the ratios are > 5. As per current DNRU2 level 1 schedule, this work will start around July 2017 with window #42 Feeder Removal. Due date for this action has been set to Nov 2017 to confirm the ratios.

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			5890	In Progress	Shielding for WBM at U2 and RWPB	· Sect 4.4.1: Shielding for WBMs at Unit 2 and RWPB should be considered and implemented if the background levels are too high for the monitors to operate effectively. TCD: October 1, 2016	Johnathon Hash	Jeff Johansson	01-Apr-17	(7 June, JJ): This work has started with the shielding considerations for the WBMs/HFFs at the RWPB. The background dose rates in the RWPB are much higher than the required background dose rates for efficient operation of the WBMs/HFFs of <50 micro-Rem/h. Some of the normal operating dose rates in the building are pegged at values > 200 micro-rem/h at locations where the monitors will be located. The Joint-Venture team are performing shielding analysis to determine the required shielding to shield the monitors with (shielding huts and/or walls) to achieve <50 micro-rem/h rates. Various locations within Unit 2 are also being investigated for shielding of the WBMs, like the south wall of the RAB side and close to where the flasks will be lowered from the RMD containing adjusters and vertical flux detectors. It is anticipated that the dose rates from the flask will take the monitors out of service during the craning time of the flasks from elevation 115m down to 100m. (22 Aug; JJ) Shielding requirements for the RWPB monitors (WBM/HFF) are being defined and designed by the JV (see attachments #1,2 & 3 for some emails on the subject). Shielding requirements for Unit 2 monitors are based on local/nearby work that may affect the local background for the monitors. To date, initial discussions have been held with the AA/VFD/HFD Replacement project team (ES Fox) and a walk down of the flask transfer route will be schedule with the project in early Sept. (03 Oct; JJ) Walk down with the ES Fox team working on the AA/VFD/HFD Replacement project was scheduled in Sept but was cancelled due to other priorities. A new walk down meeting needs to be established to walk down the path of flask transfer. RP (Jeff J) is set up a new meeting with ES Fox. (TCD: 31 Oct) (09 Nov; JJ) Walk down of the area has identified that the craning/staging area for the AA/VFD flasks is located at column line K16 - L16. The south bank of whole body monitors is located at column line A16 - B1

5694	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5891	In Progress	Contamination Control Intiatives for RFR, RWPD and SGs	· Sect 5.1: RP should review in detail the refurbishment work (e.g., CWPs for RFR in vault and RWPB, and SG work) for opportunities to reduce and control contamination spread and protection of workers against internal hazards. The outcome of this review should be documented and communicated to the Field group, HP assessors, project leaders, and REP preparers. The output from this review should be incorporated in the CWPs.	Johnathon Hash	Joe Cicchini	17-Mar-17	(June 7, JOHANSSON) Action assigned to the Field Support Section. 25AUG2016 - Initiator name changed from burkej to cicchinj due to burkej not be recognized as a lan ID
			5892	In Progress	Contamination Control Equipment	· Sect 5.1: Confirm who is procuring/deploying/controlling contamination control equipment (e.g., vacuum cleaners with HEPA filters) for all refurbishment projects (e.g., RFR, SG, and BOP work). Met with external vendor to confirm scope of purchased services regarding Munter. External review commissioned for review of recommendations for HEPA use on the project.	Johnathon Hash	Joe Cicchini	17-Mar-17	23 Feb. 16 A list of contamination control equipment and the TCD for arrival of the equipment on site has been requested of RFR. A list of contamination control equipment for Balance of Plant and SG work has been requested. All other information remains unchanged. The ownership for procurement/deployment and control of contamination control equipment among the Projects is under investigation. RFR has indicated that they are responsible for procurement of five (5) smooth bore hose Hepa vacuum cleaners; 2 - for the reactor vault, 1 for the reactor auxilliary bay and 2 for the RWPB. Arrangements will be made to assist RFR with the deployment and control of the vacuums as per the Radiation Protection Coordinator assigned to the specific task. Ownership of contamination control equipment for Balance of Plant and SG work is currently in progress and an update will be provided before 23 Feb. 2106. It has been determined that the Radiation Protection work group does not have ownership for procurement of additional contamination control equipment. The Radiation Protection department will assist with the deployment and control of "contaminated" equipment used on the projects under the guidance of the Radiation Protection Coordinators. RP may consider purchase of some equipment. Currently no CCF has been initiated however it is under review. (09 Aug; JJ) Due date changed to Sept 30, 2016. 25AUG2016 JC - A comparison between OPG sites has been initiated to develop a fleet approach to CATS devices. This exercise will produce a program that will enhance our contamination control strategy

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			5894	In Progress	Procedure Review and Update as Required for Refurbishment	· Sect 7.1: RP procedures (and associated forms, guides, instructions) should be reviewed and modified as necessary to ensure they are compatible with the Refurbishment RP organizational structure, work activities, and radiological conditions. A review of RP procedures will also identify readiness issues that need to be addressed by the RP refurbishment organization.	Johnathon Hash	Jeff Johansson	01-Apr-17	(03 Oct; JJ) N-PROC-RA-0020 "Preliminary Event Notification", was recently revised to accommodate a Notification Protocol for Nuclear Refurbishment Incidents at Nuclear Facilities (under a new section 1.2.5 of the procedure). RMO Action 5894 was derived from Recommendation (e) of NK38-REP-09701-0570560 Appendix I. The recommendation is to review RP Procedures to flag areas where certain references to RP organization and to the Shift Manager to ensure that Refurbishment workers know who to contact in the event of RP events. This review has been performed and the new revision of N-PROC-RA-0020 with the added notification protocol addresses this action. Furthermore, RP has created a Gap Assessment spreadsheet documenting the results of the RP Procedural reviews that was performed internally. This Gap Assessment needs to be assessed to determine what (if any) procedural changes are required. If required, then the changes must be requested via the current process of initiating a DCR in AS7. Programs Section Manager to initiate a review of the Gap Assessment with a target date of 31 Dec 2016 to create any required DCRs. (Nov 9; JJ) Work has started with respect to the review of the gap assessment to identify required changes. (29 Dec; JJ) Gap assessment review I/P. Due date changed to Apr 01, 2017 to accommodate additional time for review.

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			Outage Window		**Window Description**															
			000		000 – No Window Related															
951	Risk to document potential cost for units 3, 1 & 4. - Teledose Infrastructure Mod	EVENT: As a result of the recent CCF 1912 (CCF 1912 - REPLACE BLANK MODULES WITH FIBRE-OPTIC: 2-21130-EP2282) presentation to the CCB, there is a risk that no funding will be available for required AVTS insert modifications for Units 1,3 & 4. CAUSE: CCB only approved modifications funding for Unit 2. IMPACT: No AVTS available for Units 1,3 & 4.	1	Active	Johnathon Hash	Matthew Lai	16-Jan-17	Accept	01-Jul-18	2	2	2	4	1	1	1	1			
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**										
			9682	In Progress	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Johnathon Hash	Matthew Lai	08-Nov-17	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification (14 Dec; JJ) Revised "Status = Not Started" to "In Progress".										
			Outage Window		**Window Description**															
			000		000 – No Window Related															
934	Modification Delay of Penetration 2-21130-EP2282 for Radiation Protection Teledosimetry Services	EVENT: There is a risk that penetration 2-21130-EP2282 modification under MEC131147 will not be installed in time to support RFR activities. CAUSE: Associated work order WO# 4740182 has yet to receive scope acceptance and carries a level 1 modification risk category. IMPACT: Without 2-21130-EP2282 modification, RPC coverage of workers will have to commence via direct protection and running off older capacity-limited cables (Co-Ax system). The adversely impact labor costs and cause potential unplanned exposure risk increase.	3	Active	Johnathon Hash	Matthew Lai	06-Mar-17	Mitigate	01-Mar-17	5	2	2	10	1	1	1	1			
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**										

934	Modification Delay of Penetration 2-21130-EP2282 for Radiation Protection Teledosimetry Services	EVENT: There is a risk that penetration 2-21130-EP2282 modification under MEC131147 will not be installed in time to support RFR activities. CAUSE: Associated work order WO# 4740182 has yet to receive scope acceptance and carries a level 1 modification risk category. IMPACT: Without 2-21130-EP2282 modification, RPC coverage of workers will have to commence via direct protection and running off older capacity-limited cables (Co-Ax system). The adversely impact labor costs and cause potential unplanned exposure risk increase.	**9352**	In Progress	Use of Isolation Flask "tophat" to modify EP2282 prior to TCB	PO# 264750 line item #2 for CatID 1000424, Pressure Boundary Isolation flask tool runs risk of being delivered after March 2017. Vendor has informed OPG that manufacturing of product cannot begin until technical specification from 1997 (NK38-REP-57184-10001) has been updated with current codes and standards. EP2282 modification project requires tool in order to do PB modification prior to TCB in place, as per modification outline.	Matthew Lai	Sam Miao	31-Mar-17	(14-Oct-2016) NK38-DS-57100-10001 has been drafted and is being reviewed for approval to supersede NK38-REP-57184-10001. (26-Oct-2016) WO# 5079888 created to have contingency plan of using existing co-axial feed through to provide limited Teledosimetry coverage in-containment to support RFR activities. Limited teledosimetry can be provided using existing co-axial feed through for communications only. Will not be able to support Telemetry capabilities under modification to penetration is complete. (29-Nov-2016: ML) Requires CNSC Code Classification approval, because work is N285 Class 4. (29-Nov-2016; ML) CatID 1000424 Tool # DOT1000424-00001, has been confirmed by vendor that it carriers a 14-16 week delivery time. Therefore tool "tophat" will not arrive in-time to be used prior to TCB in-place. New installation strategy will be to perform modification (WO# 4740182) after TCB - no impairment to NPCS.
			9353	In Progress	2-21130-EP2282 Modification requires scope acceptance	WO# 4740182 "Replacement Blank Modules with Fiber Optic Penetrations" needs scope acceptance into DNRU2 in order to be scheduled and assessed.	Johnathon Hash	Matthew Lai	17-Apr-17	(21-OCt-2016) ML: Scope change# 30887 has been created for DNRU2 scope approval. CCF needs to be submitted for scope acceptance. (29 Dec; JJ) Latest update as summarized by Michael Carter (see attachment #1 below): · The MEC 131147 is on track to be submitted to the Station DA for approval by TCD December 9, 2016 - [Likely actual DA approval TCD is Dec 16] · Code classification letters are in review by Reg Affairs . These need to be sent off to CNSC by Dec 16 – on track · The tophat tool is due after April 1 (post TCB) . This delivery was constrained by the OEM development process plus release of OPG PO & T/S · Pre-TCB contingencies have been confirmed to support AVTS communication in the vault which mitigates any adverse impact on the RFR schedule · The CPAA decision for the work group classification is expected on Dec 12 · Design EC draft will be used to obtain budgetary execution estimates, OLW package, execution ownership, P6 scheduling, work planning , etc. This draft EC information will be available on Dec 9. · COMS to support EC release will be executed after construction work group is engaged/assigned - TCD = Early Jan 2017 · No funding deficit anticipated at this time (to be confirmed when execution estimates are in)

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

934	Modification Delay of Penetration 2-21130-EP2282 for Radiation Protection Teledosimetry	EVENT: There is a risk that penetration 2-21130-EP2282 modification under MEC131147 will not be installed in time to support RFR activities. CAUSE: Associated work order WO# 4740182 has yet to receive scope acceptance and carries a level	**Outage Window**	**Window Description**															
			023	023 - Install Bulkheads															
			024	024 - Containment Pre Test, Achieve Dew Point & Containment Test															
779	Shielding required to access vault via Airlock AL2 and associated west stairs to upper elevations.	EVENT: There is a risk that access into the vault proper via airlock AL2 will be restricted and/or restrictive due to the presence of high radiation beams emanating from RFR reactor face work, specifically open channel work. CAUSE: Due to the nature of the RFR open channel work during reactor core component removal and installation phases, high unshielded radiation beams from the face will be present in accessible areas of the vault. IMPACT: As a result, the scheduling of several vault tasks and activities (ex: vault projects windows #104/105, SG primary side clean window #62) will be limited to the a few RFR windows where the presence of high radiation beams are not generated and prominent (ex: sever bellows portion of Window 104).	3	Active	Johnathon Hash	Joe Cicchini	29-Dec-16	Mitigate	01-Apr-17	3	1	3	9	1	1	1	1
			Outage Window	**Window Description**															
			000	000 – No Window Related															
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
865	Acquisition, management, deployment and Storage of Contamination Control Equipment	EVENT: Ownership and Control of HEPA units, Vacuums, and Munter Tritium scrubbers during refurbishment is not clear. At present, there is a risk that RP will not have a program established for the procurement and management of a sufficient inventory of HEPA units, Vacuums, and Munter Tritium scrubbers. CAUSE: There is no program which describes the purchase, management, storage and use of semi-portable equipment required to ensure effective contamination control will be available and maintained on the project. IMPACT: The above risk may include components of the plan to install the large Munter units in the vault however, the risk is raised to account for the other equipment expected to be needed during refurbishment activities. This will impact RP's ability to manage its' accountability and responsibility to main contamination control during refurbishment work.	2	Active	Johnathon Hash	Scott Stafford	29-Dec-16	Mitigate	01-Jul-17	3	1	3	9	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									

865	Acquisition, management, deployment and Storage of Contamination Control Equipment	EVENT: Ownership and Control of HEPA units, Vacuums, and Munter Tritium scrubbers during refurbishment is not clear. At present, there is a risk that RP will not have a program established for the procurement and management of a sufficient inventory of HEPA units, Vacuums, and Munter Tritium scrubbers. CAUSE: There is no program which describes the purchase, management, storage and use of semi-portable equipment required to ensure effective contamination control will be available and maintained on the project. IMPACT: The above risk may include components of the plan to install the large Munter units in the vault however, the risk is raised to account for the other equipment expected to be needed during refurbishment activities. This will impact RP's ability to manage its' accountability and responsibility to main contamination control during refurbishment work.	7845	In Progress	Develop and issue a Plan that documents a Program associated with the use of Specialized Equipment for Effective Contamination Control	This action is for BHI to review existing plans, DNRU2 scope of work, and current procedures and identify gaps. If required, develop and issue a Plan that documents a Program associated with the use of Specialized Equipment for Effective Contamination Control to address the gaps. Ownership and Control of HEPA units, Vacuums, and Munter Tritium scrubbers during refurbishment is not clear. At present, there is no program which describes the purchase, management, storage and use of semi-portable equipment required to ensure effective contamination control will be available and maintained on the project. This risk may include components of the plan to install the large Munter units in the vault however, the risk is raised to account for the other equipment expected to be needed during refurbishment activities.	Johnathon Hash	Jeff Johansson	28-Apr-17	Supply Chain hold for contract PO award in negotiation. (03 Oct; JJ) RP cannot move forward on this action as the PO for BHI for the review and assessment of our current readiness/capability on the subject of Specialized Equipment for Effective Contamination Control is still outstanding. Initiate follow up with Supply Chain to determine what the hold up is and what we can do to move forward on this. (19 Oct; JJ) RFP process in progress. Latest communications attached (#1) below. Project Schedule: Kickoff meeting at OPG and gather OPG material/ information/ perspectives 11/07/2016 Completion of review of OPG material (onsite) 11/07/2016 – 11/22/2016 RP Staffing Management Plan review (onsite) 11/14/2016 – 11/22/2016 Decontamination Program & Equipment review (onsite) 11/14/2016 – 11/22/2016 Training Program Review (onsite) 11/14/2016 – 11/22/2016 Consolidate onsite assessment notes and compile draft report for OPG comment (RP Staffing Management Plan, Decontamination Program & Equipment, and Training Program) 11/28/2016 – 12/8/2016 OPG to issue comments on draft report (RP Staffing Management Plan, Decontamination Program & Equipment, and Training Program) 12/12/2016 Final Assessment Report issued to OPG 12/19/2016 (13 Feb; JJ) BHI completed their assessment of our Decon and Decon Specialized Equipment, including our Hard-to-Detect Radionuclide program in Dec 2016. The final report is attached below as attachment #2. Refurb RP is currently reviewing the report and will initiate actions to track and execute the report recommendations and to address identified gaps. Meanwhile, RP is engaged in ordering HEPAs, Vacuums, and Munters to supplement Vendor provided decon equipment.

865	Acquisition, management, deployment and Storage of Contamination Control Equipment	EVENT: Ownership and Control of HEPA units, Vacuums, and Munter Tritium scrubbers during refurbishment is not clear. At present, there is a risk that RP will not have a program established for the procurement and management of a sufficient inventory of HEPA units, Vacuums, and Munter Tritium scrubbers. CAUSE: There is no program which describes the purchase, management, storage and use of semi-portable equipment required to ensure effective contamination control will be available and maintained on the project. IMPACT: The above risk may include components of the plan to install the large Munter units in the vault however, the risk is raised to account for the other equipment expected to be needed during refurbishment activities. This will impact RP's ability to manage its' accountability and responsibility to main contamination control during refurbishment work.	7846	In Progress	Review, develop and issue a Plan that documents a Program associated with the use of Specialized Equipment/Techniques for an Effective Decontamination Program	This action is for NUVIA to review existing plans, DNRU2 scope of work, and current procedures and identify gaps. If required, develop and issue a Plan that documents a Program associated with the use of Specialized Equipment/Techniques for an Effective Decontamination Program to address any gaps. At present, there is no program which describes the purchase, management, storage and use of specialized equipment, and training required to ensure an effective decon control will be available and maintained on the project. The risk is raised to account for the a potentially large amount of equipment expected to be decontaminated during refurbishment activities, either for future re-use or on-site transfers or offsite shipments.	Johnathon Hash	Jeff Johansson	28-Apr-17	(June 7/2016, Johansson): NUVIA Canada rep (Franz Dambo) met with NR-RP on 30 May 2016 for kick-off meeting on the scope of work. (18 July; JJ) NUVIA submitted the DRAFT report on July 18, 2016 for OPG review (see attachment #1 below). (9 Aug; JJ) NUVIA and OPG NR-RP staff met to go over OPG comments and feedback on the report. NUVIA was receptive to the feedback and will be incorporating OPG comments and feedback into the final revision of the report TCD: 31 Aug. (03 Oct; JJ) OPG NR-RP and NUVIA Canada (Franz Dambo) met on Sep 30 to discuss the latest version of the report. Additional feedback and comments were fed back to NUVIA and NUVIA has agreed to incorporating the latest round of feedback and comments and finalize the report. TCD: 15 Nov. Nuvia has not submitted final report. Coninued attempts to secure. Date adjusted to January 17/2017. (13 Feb; JJ) Previous attempts to contact Nuvia for the final report have not been successful. Contacted Franz Dambo of Nuvia Canada on Feb 13 and was able to track him down in Sweden. Franz has promised to forward a copy of the final report to OPG on Feb 14-15 followed up with a face to face meeting to be scheduled early March 2017 for the final presentation of the report.
			9855	In Progress	Develop a Maintenance Strategy	Maintenance of the Munter units on the project will need to have standard approach. 1 - Work with Munter vendor to establish a service contract for project needs. 2 - Develop a spare parts strategy for internal repair and maintenance of various Munter Units. Radiation Protection is working with Maintenance to establish our long term Munter program for storage, use and maintenance.	Val Bevacqua	Johnathon Hash	31-Mar-17	RP has initiated purchase of smaller units to support just in time needs on the project. This action needs to include the large units deployed within the vault as well as smaller just in time units.
			Outage Window		**Window Description**					
			000		000 – No Window Related					

866	Reconfiguration of U2 Zone 2 Coffee Shop for use as Instrument and Dosimetry Issuing Area (RaPID Center)	EVENT: The Radiation Protection Field Support Unit requires a central location to distribute dosimetry (EPDs, PASs, H&T TLDs, etc) and organize daily work activities for the Radiation Protection Co-ordinators (RPC) providing Service Protection coverage to Orange qualified RFR workers and non-RFR personnel during the Refurbishment of Unit 2. RP has been granted the old Unit 2 Coffee Shop area located on the 107.5m elevation for this purpose. There is a risk that the required renovations and conversion of the coffee shop to a dosimetry and instrument issuing center will be delayed. CAUSE: The NR RP work group had an approved SATM D-15-0310 for use of the space on U2 107.5 elevation R-203. This area was later revoked and provided to RFR as an equipment laydown area as per ECC modifications. IMPACT: The NR RP BTU Field Unit will have a trailer available in which to perform limited administrative duties, however there will not be sufficient room for all required RPCs to perform the administrative duties required to get work/PJBs performed in a timely manner to support critical path. The location of the trailer in the Unzoned area south of U2 and does not provide easy access for RFR and non-RFR projects to contact NR RP BTU. The U2 Zone 2 coffee shop is directly adjacent to the RFR PJB area and would provide excellent access to the area. Failure to provide a central location in which to issue EPDs to RFR and Project staff as well as dealing with RP related issues could cause a delay to critical path activities and extend outage windows. Additionally, the unit 2 zone 2 coffee shop has been provided to NR RP, however funding, engineering support and project lead is required to get the area ready for service by 15 Dec 2016.	4	Active	Johnathon Hash	Jeff Johansson	01-Feb-17	Mitigate	01-May-17	3	1	3	9	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
10048	In Progress	Install IT Infrastructure within the RaPID Center (LAN and Telephone)	(1) Initiate IT infrastructure request via email to DNGD: Telecom. Action complete. See attachment #1. (2) Setup a kick-off meeting with CIO representatives to discuss path forward on the IT infrastructure for the RaPID center. Action Complete. See Attachment #2. (3) Perform field walk down (RP and CIO) of the area of interest to gauge the current status of LAN availability/capability within the local vicinity of the RaPID center. Action: In-Progress. TCD for walk down is Friday, Feb 3. (CIO rep attending: Al Dharshi. (see attachment #3)	Johnathon Hash	Jeff Johansson	01-Apr-17	(01 Feb; JJ) Action initiation.

Outage Window	Window Description
000	000 – No Window Related

564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	3	Active	Johnathon Hash	Jeff Johansson	01-Feb-17	Mitigate	30-Dec-17	3	2	2	6	2	2	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments

564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5876	In Progress	Strategy for smear samples to determine radionuclide characterization for U2	a) Source Term Characterization · Section 2.2: Develop a strategy for taking smear samples for the purpose of source term characterization of Unit 2 when radioactive systems are opened up for refurbishment. Samples locations should include radioactive systems in Unit 2, RWPB, and Fuel Handling. Once samples are taken, they should be analyzed radio-chemically and the conclusions with respect to dose contributions from the AMEC report should be validated. Also calculate the beta-gamma: alpha ratio to confirm capability of WBM to indicate the presence of alpha emitting radionuclides in the body and continued use of pancake for both beta-gamma measurement and, by inference, alpha presence (as per N-INS-09071-10013).	Johnathon Hash	Joe Cicchini	01-Apr-17	(7 June Johansson): Initiate a search of the smears that were taken during 2015 VBO on Unit 2 and, if found, perform count on the smears and document results. (18 July; JJ) A search for the smears that were apparently taken on Unit 2 during the 2015 VBO was unsuccessful. Decision to initiate a new set of smears on Unit 4 during D1641 was made and smears were taken. Some of the areas/systems include in this smear program are (see attachment #1 below for more details): Floor under pressurizer x2 Floor near ball screw pit. 1 x east, 1 x west. Base of the boilers (around manway, bolts etc) 1 x east, 1 x west Mod room (051 or 052 on the valving) ESC (scrap pipe on platform) Reach inside (do not enter) feeder cabinet on 100 elev and smear walkway Top of Bleed condenser 107.5 elev SDC The smears were sent to the Chemistry lab for initial analysis. Lab results have been received, along with the smears. Additional alpha counting of the smears will be arranged with Kinectrics. (10 Aug; JJ) See email attachment #2 below for results of initial counts of the smears performed at the DN Chem Lab. Preparation in progress to send the smears to Kinectrics for alpha analysis. 25AUG2016 JC Smears being processed for shipment 14OCT2016 - Several smears have been processed and analyzed in previous outages this data will be used to anticipate and Unit 2 specific smears will be collected. (22 Nov; JJ) Additional smears were taken by DN RP in Unit 3 and Unit 4 in 2015/2016 outages respectively (see attachment #4 email). Together with similar legacy data (see attachment #3), attachment #4 data from U3 and 4 will be reviewed and analyzed to confirm the beta-gamma to alpha ratio to confirm that capability of WBMs to indicate the presence of Alpha emitting radionuclides, and the continued use of pancake meters for inference of alpha activity. (29 Dec; JJ) The above mentioned U3 & U4 smear analysis results will be reviewed by NRRP HPs to confirm beta-

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			5883	In Progress	Darlington Routine Radiation Surveys Instruction Modified to include Unit 2 Refurbishment	· Sect 4.1.1: Modify D-INS-09071-10012, Darlington Routine Radiation Surveys, to expand the routine alpha monitoring program for Unit 2 refurbishment. Moving due date to June 30 in order to capture recommendations from an external report for Hard to Detect Nuclide Monitoring. (7 June, JOHANSSON): moved due date to Aug 31, 2016.	Johnathon Hash	Jeff Johansson	03-Apr-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. (09 Nov; JJ) The highest potential for alpha presence may occur during RFR series work (EF cutting, PT cut, etc...). NRRP ALARA are preparing RFR series specific RPEGs that will include requirements for routine and non-routine alpha surveys/smears. The Darlington Routine Survey instruction will not be revised to incorporate such requirements as it is tracked under the RPEGS. (01 Feb; JJ) DRAFT Routine Survey RPEG has been issued for RP review (see attachment #1). This RPEG was discussed with the Field Section and an action was assigned to the Field Section to determine the level of effort/resources that will take to execute the proposed RPEG surveys.

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			5886	In Progress	Confirm Alpha Counting room for Refurbishment	· Sect 4.1.1: Confirm the availability of a facility for counting alpha contamination samples.	Johnathon Hash	Joe Cicchini	17-Mar-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. Explore Ryan's suggestion for NR-RP to own and operate the Darlington iSolo counting room, and offer to perform any Darlington RP smears and train their personnel as well. (July 14; JJ): In addition to securing a dedicated alpha counting room for Refurbishment work, it was suggested that HPD perform a QA program for the results by analyzing a fixed percentage of the smears collected and counted, and documenting the results in a QA report for audit purposes. This will be include in the PAS Sampling Policy that is tracked under Action #5880. 25AUG2016 JC - Refurb RP will be working with station RP to develop a smear counting strategy that will benefit both organizations. ***Initiator name changed from BurkeJ to CicchinJ due to Lan ID of burkej not being recognized.
			5887	In Progress	Confirm Monitoring Compliance with Alpha Contamination Limits	· Sect 4.2.1/4.3.1: Confirm through ongoing source term/alpha characterization of Unit 2 that the beta-gamma: alpha activity ratio is greater than 5. This will confirm that pancake and WBM are sufficient to confirm compliance with alpha contamination limits.	Johnathon Hash	Jeff Johansson	30-Sep-17	(7 June; JJ): Consider integrating this requirement into the NR-RP Routine Survey program. If appropriate, close this action to action # 5883. (18 July; JJ): Post June 13 meeting with HPD, a recommendation was made for NR-RP to explore other instruments for Alpha counting (other than iSolos). It was also suggested to have HPD Instrument group involved in this search. (03 Oct; JJ) The recommendation is to confirm through on-going source term and/or alpha characterization studies during refurbishment activities that the beta-gamma: alpha ratio activity is still > 5. Once RFR work commences in unit 2, smears of open system piping/equipment will be performed and analyzed to confirm the ratios are > 5. As per current DNRU2 level 1 schedule, this work will start around July 2017 with window #42 Feeder Removal. Due date for this action has been set to Nov 2017 to confirm the ratios.

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			5890	In Progress	Shielding for WBM at U2 and RWPB	· Sect 4.4.1: Shielding for WBMs at Unit 2 and RWPB should be considered and implemented if the background levels are too high for the monitors to operate effectively. TCD: October 1, 2016	Johnathon Hash	Jeff Johansson	01-Apr-17	(7 June, JJ): This work has started with the shielding considerations for the WBMs/HFFs at the RWPB. The background dose rates in the RWPB are much higher than the required background dose rates for efficient operation of the WBMs/HFFs of <50 micro-Rem/h. Some of the normal operating dose rates in the building are pegged at values > 200 micro-rem/h at locations where the monitors will be located. The Joint-Venture team are performing shielding analysis to determine the required shielding to shield the monitors with (shielding huts and/or walls) to achieve <50 micro-rem/h rates. Various locations within Unit 2 are also being investigated for shielding of the WBMs, like the south wall of the RAB side and close to where the flasks will be lowered from the RMD containing adjusters and vertical flux detectors. It is anticipated that the dose rates from the flask will take the monitors out of service during the craning time of the flasks from elevation 115m down to 100m. (22 Aug; JJ) Shielding requirements for the RWPB monitors (WBM/HFF) are being defined and designed by the JV (see attachments #1,2 & 3 for some emails on the subject). Shielding requirements for Unit 2 monitors are based on local/nearby work that may affect the local background for the monitors. To date, initial discussions have been held with the AA/VFD/HFD Replacement project team (ES Fox) and a walk down of the flask transfer route will be schedule with the project in early Sept. (03 Oct; JJ) Walk down with the ES Fox team working on the AA/VFD/HFD Replacement project was scheduled in Sept but was cancelled due to other priorities. A new walk down meeting needs to be established to walk down the path of flask transfer. RP (Jeff J) is set up a new meeting with ES Fox. (TCD: 31 Oct) (09 Nov; JJ) Walk down of the area has identified that the craning/staging area for the AA/VFD flasks is located at column line K16 - L16. The south bank of whole body monitors is located at column line A16 - B1

5694	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5891	In Progress	Contamination Control Intiatives for RFR, RWPD and SGs	· Sect 5.1: RP should review in detail the refurbishment work (e.g., CWPs for RFR in vault and RWPB, and SG work) for opportunities to reduce and control contamination spread and protection of workers against internal hazards. The outcome of this review should be documented and communicated to the Field group, HP assessors, project leaders, and REP preparers. The output from this review should be incorporated in the CWPs.	Johnathon Hash	Joe Cicchini	17-Mar-17	(June 7, JOHANSSON) Action assigned to the Field Support Section. 25AUG2016 - Initiator name changed from burkej to cicchinj due to burkej not be recognized as a lan ID
			5892	In Progress	Contamination Control Equipment	· Sect 5.1: Confirm who is procuring/deploying/controlling contamination control equipment (e.g., vacuum cleaners with HEPA filters) for all refurbishment projects (e.g., RFR, SG, and BOP work). Met with external vendor to confirm scope of purchased services regarding Munter. External review commissioned for review of recommendations for HEPA use on the project.	Johnathon Hash	Joe Cicchini	17-Mar-17	23 Feb. 16 A list of contamination control equipment and the TCD for arrival of the equipment on site has been requested of RFR. A list of contamination control equipment for Balance of Plant and SG work has been requested. All other information remains unchanged. The ownership for procurement/deployment and control of contamination control equipment among the Projects is under investigation. RFR has indicated that they are responsible for procurement of five (5) smooth bore hose Hepa vacuum cleaners; 2 - for the reactor vault, 1 for the reactor auxilliary bay and 2 for the RWPB. Arrangements will be made to assist RFR with the deployment and control of the vacuums as per the Radiation Protection Coordinator assigned to the specific task. Ownership of contamination control equipment for Balance of Plant and SG work is currently in progress and an update will be provided before 23 Feb. 2106. It has been determined that the Radiation Protection work group does not have ownership for procurement of additional contamination control equipment. The Radiation Protection department will assist with the deployment and control of "contaminated" equipment used on the projects under the guidance of the Radiation Protection Coordinators. RP may consider purchase of some equipment. Currently no CCF has been initiated however it is under review. (09 Aug; JJ) Due date changed to Sept 30, 2016. 25AUG2016 JC - A comparison between OPG sites has been initiated to develop a fleet approach to CATS devices. This exercise will produce a program that will enhance our contamination control strategy

564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5893	In Progress	Contamination Control - Ventilated Tents	· Sect 5.1: RP should consider the requirements for ventilated tents and exhaust HEPA filters. This will include the design and integrity testing.	Johnathon Hash	Joe Cicchini	17-Mar-17	RP for Refurbishment has considered the use of ventilated tents and exhaust HEPA units with filters. RP will utilize N-INS-03420-10005 on Use and Maintenance of Portable HEPA filter ventilation units for all hepa units used in association with vented tents. RP Refurbishment has agreed to perform the HEPA filter changes required for effective operation of the unit(s). RP Refurbishment will not purchase the HEPA units,nor does RP have budget to procure the HEPA units as this part of the "consumable" budget was given to Maintnenance Refurbishment. Ventilated tents are used to control contamination, however, there is no integrity testing procedure to date, other than the use of a smoke bomb to check the tent for air flow. An alternate source of testing tent integrity would be to use a Magnehelic guage to determine air flow. A process/procedure to perform integrity testing of tented material needs to be generated. (22 Aug; JJ) Consulted with Refurb Maintenance as to an RQE budget for RP HEPAs, Vacuums, and Munters. Tom Carvin will follow up with Mtce Manager. (15OCT2016) - Updated last reviewed date. BHI assessment procurement is in early stages. (09 Nov;JJ) BHI consultants arrived at Darlington on Nov 9. Assessment I/P.
			5894	In Progress	Procedure Review and Update as Required for Refurbishment	· Sect 7.1: RP procedures (and associated forms, guides, instructions) should be reviewed and modified as necessary to ensure they are compatible with the Refurbishment RP organizational structure, work activities, and radiological conditions. A review of RP procedures will also identify readiness issues that need to be addressed by the RP refurbishment organization.	Johnathon Hash	Jeff Johansson	01-Apr-17	(03 Oct; JJ) N-PROC-RA-0020 "Preliminary Event Notification", was recently revised to accommodate a Notification Protocol for Nuclear Refurbishment Incidents at Nuclear Facilities (under a new section 1.2.5 of the procedure). RMO Action 5894 was derived from Recommendation (e) of NK38-REP-09701-0570560 Appendix I. The recommendation is to review RP Procedures to flag areas where certain references to RP organization and to the Shift Manager to ensure that Refurbishment workers know who to contact in the event of RP events. This review has been performed and the new revision of N-PROC-RA-0020 with the added notification protocol addresses this action. Furthermore, RP has created a Gap Assessment spreadsheet documenting the results of the RP Procedural reviews that was performed internally. This Gap Assessment needs to be assessed to determine what (if any) procedural changes are required. If required, then the changes must be requested via the current process of initiating a DCR in AS7. Programs Section Manager to initiate a review of the Gap Assessment with a target date of 31 Dec 2016 to create any required DCRs. (Nov 9; JJ) Work has started with respect to the review of the gap assessment to identify required changes. (29 Dec; JJ) Gap assessment review I/P. Due date changed to Apr 01, 2017 to accommodate additional time for review.

564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	**5895**	In Progress	Readiness Assessment for Hard to Detect Radionulcides	· Sect 8.1: An assessment of the RP's readiness to manage hard to detect hazards should be completed prior to breaker open as well as a follow-up assessment at an appropriate time during the refurbishment.	Johnathon Hash	Jeff Johansson	31-Mar-17	(June 7, JOHANSSON): Explore and plan for a self-assessment (SA) to be performed by an Internal Team (of RP personnel). Ensure an SA entry is initiated in the Self-Assessment database for this deliverable. (Sept 13/2016: JJ) Changed due date from Sept 16 to Oct 15 as additional time is required to schedule and complete the assessment. (19 Oct: JJ) Due date extended to accommodate planning and execution of the assessment. NR RP will plan to have this assessment scheduled to be completed by end of Dec 2016. (23 Nov; JJ) A recent snapshot assessment scope of work performed by BHI (Nov 8-22) was expanded to include the subject of readiness to manage hard to detect radionuclides. This assessment report is currently being prepared and finalized and will be attached herein once completed and issued. Any gaps identified from the assessment will be tracked as actions under Risk #0564. (29 Dec; JJ) BHI draft report was submitted to OPG NRRP for review. Comments were sent back to BHI for disposition and issuance of the final report. (13 Feb; JJ) BHI Final Report has been submitted to OPG follow successful C&D process (see attachment #1 below). OPG is currently reviewing the final report with a view to initiate follow up actions to address the identified gaps and recommendations from the report.																
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864	Identifying priority for staff within our BTU Project ranks and staff assigned to BTU Refurbishment	EVENT: There is a risk that RP may not have documented direction and planning for staff who are assigned to Refurb when non routine events occur. The risk identified includes (but is not limited to) response to IPG events, response to events within the refurb project but outside of our U2 island, various facility events and work priorities during significant competing projects (such as an outage). CAUSE: As part of RP resource planning and identification, the need for emergency response role(s) was not clearly identified and defined. IMPACT: The risk may impact RP's ability to respond to non-routine events such as those events requiring RP participation from a Radiological perspective.	2	Active	Johnathon Hash	Joe Cicchini	22-Feb-17	Mitigate	16-Jun-17	2	2	3	6	1	2	1	2					
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**															
			7837	In Progress	RP Field Support Section - RP Field Execution Handbook	This action is to research, prepare and issue a Field Execution Handbook for use by members of the NR-RP Department, especially the Field Support Section RPCs to assist the RPCs with a working reference of expectations. The handbook is a guide to the expectations for OPG Radiation Protection personnel. The guide is not intended to be all inclusive or to supersede approved procedures given that it may be published yearly and therefore not consistent with current revision of the procedures referenced in the handbook. Proposed steps: - prepare Task Request (N-FORM-11551) and RFP forms, and initiate/approve MR - Route above paperwork for approval - Submit to OSS Contract Management group. - Follow process to select vendor of choice. - Work with Supply Chain to issue PO - Start the work. Note: will require funding as there is no remaining OSS funds for this work.	Johnathon Hash	Joe Cicchini	17-May-17	(21 June; JJ): This action has been assigned to Mike Armstrong to execute. (Aug 10; JJ) Field Execution Guide I/P, with 10% progress to completion. 25AUG2016 JC Guide in progress, 15% complete. (14 Sep; JJ) Guide is 25% complete. JC- Guide is 35% complete. (Maps concept is complete) JC - Guide is 60% complete. Critical maps are complete. 14OCT JC - (29DEC2016) Draft guide is complete. JH - Draft guide is being reviewed for additional content. Additional content to be provided by end of Feb 2017.													
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867	Additional cost for remote RP training capability in the classroom and Mock-up facility	EVENT: RP has identified the need to have some RP Simulator training administered at the Mock-Up during just-in-time RFR series training activities. There is a risk that the procurement, installation, testing, and commissioning of required RP training tools (ex: Q-Track, Teletrix) will be delayed. CAUSE: Delay in obtaining quotes and procurement of the relevant software. IMPACT: The Mock-up facility technology can replicate beam hazards which would be very beneficial to series testing and practical mock-up exposure, as well as in the training of the RPCs for RP. Delay in getting the simulators in place will impact the ability to fully integrate radiological training simulation into the RFR JIT program, and the RP Yellow/Green training of RPCs.	3	Active	Johnathon Hash	Jeff Johansson	01-Feb-17	Mitigate	01-Apr-17	3	1	2	6	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8816	In Progress	Initiate process to obtain quote from Q-Track Vendor with goal to purchase Q-track and commisioned for use at the DEC Mock-up facility	HPD Remote Monitoring section to initiate process to obtain a quote from the Q-track vendor. Q-Track has a Dosimulation™ Radiation Worker Training System which uses patented technology, the system automatically and instantaneously correlates a worker's actual location with a trainer-controlled, simulated-radiation environment. The dosimeter: displays cumulative radiation exposure has internal-alarms when radiation limits are exceeded The system also has a mapping tool allowing a trainer to review an exercise and empowering him to streamline any operation procedure proposals to minimize manpower and radiation exposure.	Johnathon Hash	Jeff Johansson	28-Apr-17	(09 Aug; JJ) Action initiation. Aug 29th update. Met with supply chain mid august to review intended SOW and working with Supply Chain to complete SOW for quotes. (Sep 13/2016: JJ) Ryan McConnell has prepared the Scope of Work (SOW) to support the RFP. Submitted the SOW to Supply Chain (SC) for review. Comments/feedback from Supply Chain received and are currently being incorporated. Next steps: re-submit to SC for processing of the RFP (19 Oct; JJ) Reassigned the action to Johansson, and added interested parties (Ryan McC and Joe C). Action will be delegated to Ryan to prepare the SOW and initiate MR to purchase. (28 Dec; JJ) Ryan McConnell has prepared a draft SOW for the RFP. Currently being reviewed. (01 Feb; JJ) Training Simulation Equipment - received the RFQ's from Supply Chain for the training simulation equipment (Teletrix from Teletrix, Q-Track from IIS/Gamble, and Sim-Teq from Mirion). RP is currently reviewing the quotes from the proponents, and to provide Finance with recommendations on which to purchase. (13 Feb; JJ) Additional information is being requested of the proponents. Supply Chain has been informed and they have made contact with the proponents for the additional information. See attachments #1 and 2 for email details and information being requested.

867	Additional cost for remote RP training capability in the classroom and Mock-up facility	EVENT: RP has identified the need to have some RP Simulator training administered at the Mock-Up during just-in-time RFR series training activities. There is a risk that the procurement, installation, testing, and commissioning of required RP training tools (ex: Q-Track, Teletrix) will be delayed. CAUSE: Delay in obtaining quotes and procurement of the relevant software. IMPACT: The Mock-up facility technology can replicate beam hazards which would be very beneficial to series testing and practical mock-up exposure, as well as in the training of the RPCs for RP. Delay in getting the simulators in place will impact the ability to fully integrate radiological training simulation into the RFR JIT program, and the RP Yellow/Green training of RPCs.	**8817**	In Progress	Initiate process to obtain quote from Teletrix Vendor with goal to purchase Teletrix and commissioned for use with the BTU RPC Training facility	HPD Remote Monitoring section to initiate process to obtain a quote from the Teletrix vendor. Teletrix Radiation Training Simulator is a training tool providing true to life meter readings without exposure to radiation sources. it utilizes RF remote control rather than ionizing radiation as a source, trainees experience a radiation meter's entire indicating range while learning in a safe environment that mimics real life operations. Teletrix will be a tool that can supplement the Yellow/Green badge training practical exercises.	Johnathon Hash	Jeff Johansson	30-Apr-17	(09 Aug; JJ) Action initiation. Aug 29 - met with Supply Chain. Assistance and support for SOW to address both remote classroom capabilities (DEC Mock up included). (Sep 13/2016: JJ) Ryan McConnell has prepared the Scope of Work (SOW) to support the RFP. Submitted the SOW to Supply Chain (SC) for review. Comments/feedback from Supply Chain received and are currently being incorporated. Next steps: re-submit to SC for processing of the RFP (19 Oct; JJ) Reassigned the action to Johansson, and added interested parties (Ryan McC and Joe C). Action will be delegated to Ryan to prepare the SOW and initiate MR to purchase. MR Approved Dec 16th. J-Hash (28 Dec; JJ) Ryan McConnell has prepared a draft SOW for the RFP. Currently being reviewed. (01 Feb; JJ) Training Simulation Equipment - received the RFQ's from Supply Chain for the training simulation equipment (Teletrix from Teletrix, Q-Track from IIS/Gamble, and Sim-Teq from Mirion). RP is currently reviewing the quotes from the proponents, and to provide Finance with recommendations on which to purchase.										
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871	RP Staffing for PCC and High Hazard Oversight support risk	EVENT: Refurbishment PCC Support and High Hazard Oversight (HHO) requirements may be 24/7 or close to 24/7 operations/activities. There is a risk that RP staffing may not be sufficient to provide complete support for these activities. CAUSE: Lack of qualified RP staff to provide the required coverage. IMPACT: This may impact the requirement to staff PCC/HHO operations at the required rate, thus impacting project schedules and activities.	3	Active	Johnathon Hash	Scott Stafford	01-Feb-17	Mitigate	31-Mar-17	3	1	2	6	1	1	2	2							
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**													
			8240	In Progress	High Hazard Oversight / PCC Plan	Structure a plan for High Radiological work oversight as well as PCC staffing will be defined. Next steps would then be determining an effective schedule for staff to support as required. This specific support was initially in the RQE however budget compression removed this cost from our 24 / 7 critical path schedule.	Johnathon Hash	Scott Stafford	31-Mar-17	(09 Aug; JJ) A plan is being developed to review various schedules and shifts to accommodate 24/7 service for HHW oversight, as well as the required RP qualifications for such resources to staff these shifts. 23 Aug SS: Updated HHW oversight schedule and Oversight demand needs developed. 22 Sept SS: HHW oversight schedule/demand schedule updated. Temporary staff positions for Org I/P 11 Oct SS: HHW oversight schedule attached. Temp Staff positions for org I/P 23Nov SS: Org change I/P. Date moved to Dec 15 to allow org change to be completed for HHW oversight. PCC coverage being performed on weekends by Duty ALARA HP. 14-Dec SS: Date moved to January 16th to allow org change to be completed for HHW oversight. Approvals received to create a shift for Duty ALARA HP 24/7 coverage.										
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868	Non RQE identified cost for wireless integration of RP survey, shipment and Inventory data	EVENT: There is a risk that some specific RP Field Support services (such as radioactive shipping, inventory tracking/control of radioactive storage areas, close to instant reporting of online survey results, to name a few) will not be as expedient as some Projects/Vendors may expect to maintain critical/near-critical path work. CAUSE: Lack of an electronic/high tech process for the input and communication of RP related information to all parties of interest. IMPACT: This will impact the ability for field update to shipping paperwork, site inventory control of radioactive storage areas, and up to the minute survey results updates on all media forums. We have a bounding vendor quote and we are working through that at present. The RFP process as well as CCF are in progress. June 30, 2016 - J. Hash - Met with Executive VP and DOM for Project. Discussed the use of a third party vendor for this service. Was challenged to seek assistance from DataGlance. This is the Vendor who secured the Electronic work Package contract through Fleet Maintenance. Engaged maintenance for contact information and support towards seeking our deliverables through DataGlance. In Progress.		Active	Johnathon Hash	Joe Cicchini	01-Feb-17	Mitigate	28-Apr-17	5	1	1	5	1	1	1	1
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**								
			8237	In Progress	Seek support for wireless applications within the RP project organization	This action will track our engagement with DataGlance to assist / provide technical support for using and integrating some wireless applications for the project within RP.	Johnathon Hash	Joe Cicchini	31-Mar-17	(09 Aug; JJ) Initiated discussions with DataGlance CFAM (see attachment 31 below). Next step is to setup a meeting with the CFAM to share NR-RP needs with the DataGlance team. (03 Oct; JJ) Need to re-establish contact with the CFAM (Ed Lei) to discuss potential application of DataGlance for RP field work coordination/management. Email sent to Ed Lei (see attachment #2) for a meeting to discuss opportunities to use DataGlance. 15OCT2016 JC - JC/JJ attended a demonstration on 06OCT. This initiative as many applications applicable to RP. Specifically the availability of the CITRIX network wirelessly, allowing RPC to access the computer system from the job site. (01 Feb; JJ) Further discussions with IT CIO on this and it was recommended that DataGlance network will provide limited to no advantages for RP as it is specifically written for Maintenance electronic work packages, and interfaces with Asset Suite. RP applications (such as VSDS, RIS, etc...) interfaces with non Asset Suite software which DataGlance will not be able to provide. RP should consider using OPG Citrix to access OPG business LAN software by networking with the Refurbishment Unit 2 WiFi. RP is taking these recommendations under consideration.				
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565	Insufficient Qualified Radiation Protection Coordinators (BTU RPCs) to support Execution	EVENT: There is a risk that an insufficient number of qualified Radiation Protection Coordinators (RPCs) will be available to successfully provide service protection oversight for Fleet and Refurbishment radiological work that is being performed by EPC contractors. CAUSE: Due to low numbers of currently qualified BTU Trades RPC's plus attrition and insufficient training and qualification of new BTU Trades RPCs prior to execution of Refurbishment activities and opportunities with other industrial project in the province. IMPACT: May lead to schedule delays and cost overruns or could cause RP events due to lack of oversight or lack of properly experienced oversight.	3	Active	Johnathon Hash	Joe Cicchini	22-Feb-17	Mitigate	13-Oct-17	2	1	2	4	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**								

565	Insufficient Qualified Radiation Protection Coordinators (BTU RPCs) to support Execution	EVENT: There is a risk that an insufficient number of qualified Radiation Protection Coordinators (RPCs) will be available to successfully provide service protection oversight for Fleet and Refurbishment radiological work that is being performed by EPC contractors. CAUSE: Due to low numbers of currently qualified BTU Trades RPC's plus attrition and insufficient training and qualification of new BTU Trades RPCs prior to execution of Refurbishment activities and opportunities with other industrial project in the province. IMPACT: May lead to schedule delays and cost overruns or could cause RP events due to lack of oversight or lack of properly experienced oversight.	7672	In Progress	Periodic Assessment of Factors and Conditions that may impact RPC Supply for Unit 2 Refurbishment.	Periodically assess the following factors/conditions to determine what impact, if any, on the BTU RPC supply: - Training schedule (i.e., BTU RPC Yellow/Green RP qualification training) - Attrition associated with existing pool of BTU RPCs. - Bruce Power Main Component Replacement (MCR) campaign impact on OPG BTU RPC supply and training. - other related factors/conditions that may impact the supply/demand. 14JUN2016 JC: Refurb Prerequisites OPEX has identified the practice of adjusting the work schedule to address production schedules. If this approach is going to be used for Refurb Execution, the Radiation Protection's current staffing model will be challenged to support all work. Specific changes that would affect how we provide protection could include things like changing to a 24/7 model instead of the current understood 20hrs/day schedule. Staggered lunches, and resultant the need to have continuous RP support throughout everyday will also have to be considered against our current proposed support system. (JC)02AUG2016:CCF to be presented for the installation of a shield wall inside Airlock #2 to allow access to the stairs to the 111m elevation. This CCF is inclusive of all aspects of the wall procurement and subsequent installation. Having a shield wall will open up work windows for other groups, creating more demand for Radiation Protection Support. (JC) 30SEPT2016 Training I/p. RPCs in place and ready. (JC) 29DEC Class 8 training to begin 23JAN2017, this will bring the number of RPCs up to 166 techs available.	Johnathon Hash	Joe Cicchini	15-Sep-17	This is an on-going periodic assessment action so the due and completed dates are set to the end of the Unit 2 refurbishment window. If needed, a new action can be generated for future units. (JC)08SEPT2016 4on - 4off schedule is being used to increase RPC numbers per shift and provide 24/7 coverage. This model will provide for more depth to crew sizes and the availability of workers to supplement crews (Overtime) if required. (JC)14OCT2016 Class 7 is in progress and Classes 8 and 9 are scheduled for early 2017.
			8110	In Progress	Review and Revisit BTU RPC Demand/Supply for Additional Yellow Badge Classes	Review and revisit BTU RPC demand/supply to determine need for additional classes.	Johnathon Hash	Joe Cicchini	31-Mar-17	25AUG2016 JC Currently, our model supports our plan. 15OCT2016 JC - Two classes are currently scheduled for 2017 (Class 8&9) the requirement for additional classes are to be determined. 16JAN2017 JH - Third class added to 2017. Currently a Q4 course is being considered by not committed at this time. Decision by end of Q1.

Outage Window	Window Description
161	161 - RFR-Containment Isolation and Islanding
163	163 - RFR-Remove FM Bridge and Install RTP

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			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

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			5883	In Progress	Darlington Routine Radiation Surveys Instruction Modified to include Unit 2 Refurbishment	· Sect 4.1.1: Modify D-INS-09071-10012, Darlington Routine Radiation Surveys, to expand the routine alpha monitoring program for Unit 2 refurbishment. Moving due date to June 30 in order to capture recommendations from an external report for Hard to Detect Nuclide Monitoring. (7 June, JOHANSSON): moved due date to Aug 31, 2016.	Johnathon Hash	Jeff Johansson	03-Apr-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. (09 Nov; JJ) The highest potential for alpha presence may occur during RFR series work (EF cutting, PT cut, etc...). NRRP ALARA are preparing RFR series specific RPEGs that will include requirements for routine and non-routine alpha surveys/smears. The Darlington Routine Survey instruction will not be revised to incorporate such requirements as it is tracked under the RPEGS. (01 Feb; JJ) DRAFT Routine Survey RPEG has been issued for RP review (see attachment #1). This RPEG was discussed with the Field Section and an action was assigned to the Field Section to determine the level of effort/resources that will take to execute the proposed RPEG surveys.

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			5886	In Progress	Confirm Alpha Counting room for Refurbishment	· Sect 4.1.1: Confirm the availability of a facility for counting alpha contamination samples.	Johnathon Hash	Joe Cicchini	17-Mar-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. Explore Ryan's suggestion for NR-RP to own and operate the Darlington iSolo counting room, and offer to perform any Darlington RP smears and train their personnel as well. (July 14; JJ): In addition to securing a dedicated alpha counting room for Refurbishment work, it was suggested that HPD perform a QA program for the results by analyzing a fixed percentage of the smears collected and counted, and documenting the results in a QA report for audit purposes. This will be include in the PAS Sampling Policy that is tracked under Action #5880. 25AUG2016 JC - Refurb RP will be working with station RP to develop a smear counting strategy that will benefit both organizations. ***Initiator name changed from BurkeJ to CicchinJ due to Lan ID of burkej not being recognized.
			5887	In Progress	Confirm Monitoring Compliance with Alpha Contamination Limits	· Sect 4.2.1/4.3.1: Confirm through ongoing source term/alpha characterization of Unit 2 that the beta-gamma: alpha activity ratio is greater than 5. This will confirm that pancake and WBM are sufficient to confirm compliance with alpha contamination limits.	Johnathon Hash	Jeff Johansson	30-Sep-17	(7 June; JJ): Consider integrating this requirement into the NR-RP Routine Survey program. If appropriate, close this action to action # 5883. (18 July; JJ): Post June 13 meeting with HPD, a recommendation was made for NR-RP to explore other instruments for Alpha counting (other than iSolos). It was also suggested to have HPD Instrument group involved in this search. (03 Oct; JJ) The recommendation is to confirm through on-going source term and/or alpha characterization studies during refurbishment activities that the beta-gamma: alpha ratio activity is still > 5. Once RFR work commences in unit 2, smears of open system piping/equipment will be performed and analyzed to confirm the ratios are > 5. As per current DNRU2 level 1 schedule, this work will start around July 2017 with window #42 Feeder Removal. Due date for this action has been set to Nov 2017 to confirm the ratios.

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			5890	In Progress	Shielding for WBM at U2 and RWPB	· Sect 4.4.1: Shielding for WBMs at Unit 2 and RWPB should be considered and implemented if the background levels are too high for the monitors to operate effectively. TCD: October 1, 2016	Johnathon Hash	Jeff Johansson	01-Apr-17	(7 June, JJ): This work has started with the shielding considerations for the WBMs/HFFs at the RWPB. The background dose rates in the RWPB are much higher than the required background dose rates for efficient operation of the WBMs/HFFs of <50 micro-Rem/h. Some of the normal operating dose rates in the building are pegged at values > 200 micro-rem/h at locations where the monitors will be located. The Joint-Venture team are performing shielding analysis to determine the required shielding to shield the monitors with (shielding huts and/or walls) to achieve <50 micro-rem/h rates. Various locations within Unit 2 are also being investigated for shielding of the WBMs, like the south wall of the RAB side and close to where the flasks will be lowered from the RMD containing adjusters and vertical flux detectors. It is anticipated that the dose rates from the flask will take the monitors out of service during the craning time of the flasks from elevation 115m down to 100m. (22 Aug; JJ) Shielding requirements for the RWPB monitors (WBM/HFF) are being defined and designed by the JV (see attachments #1,2 & 3 for some emails on the subject). Shielding requirements for Unit 2 monitors are based on local/nearby work that may affect the local background for the monitors. To date, initial discussions have been held with the AA/VFD/HFD Replacement project team (ES Fox) and a walk down of the flask transfer route will be schedule with the project in early Sept. (03 Oct; JJ) Walk down with the ES Fox team working on the AA/VFD/HFD Replacement project was scheduled in Sept but was cancelled due to other priorities. A new walk down meeting needs to be established to walk down the path of flask transfer. RP (Jeff J) is set up a new meeting with ES Fox. (TCD: 31 Oct) (09 Nov; JJ) Walk down of the area has identified that the craning/staging area for the AA/VFD flasks is located at column line K16 - L16. The south bank of whole body monitors is located at column line A16 - B1

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			5892	In Progress	Contamination Control Equipment	· Sect 5.1: Confirm who is procuring/deploying/controlling contamination control equipment (e.g., vacuum cleaners with HEPA filters) for all refurbishment projects (e.g., RFR, SG, and BOP work). Met with external vendor to confirm scope of purchased services regarding Munter. External review commissioned for review of recommendations for HEPA use on the project.	Johnathon Hash	Joe Cicchini	17-Mar-17	23 Feb. 16 A list of contamination control equipment and the TCD for arrival of the equipment on site has been requested of RFR. A list of contamination control equipment for Balance of Plant and SG work has been requested. All other information remains unchanged. The ownership for procurement/deployment and control of contamination control equipment among the Projects is under investigation. RFR has indicated that they are responsible for procurement of five (5) smooth bore hose Hepa vacuum cleaners; 2 - for the reactor vault, 1 for the reactor auxilliary bay and 2 for the RWPB. Arrangements will be made to assist RFR with the deployment and control of the vacuums as per the Radiation Protection Coordinator assigned to the specific task. Ownership of contamination control equipment for Balance of Plant and SG work is currently in progress and an update will be provided before 23 Feb. 2106. It has been determined that the Radiation Protection work group does not have ownership for procurement of additional contamination control equipment. The Radiation Protection department will assist with the deployment and control of "contaminated" equipment used on the projects under the guidance of the Radiation Protection Coordinators. RP may consider purchase of some equipment. Currently no CCF has been initiated however it is under review. (09 Aug; JJ) Due date changed to Sept 30, 2016. 25AUG2016 JC - A comparison between OPG sites has been initiated to develop a fleet approach to CATS devices. This exercise will produce a program that will enhance our contamination control strategy

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			5894	In Progress	Procedure Review and Update as Required for Refurbishment	· Sect 7.1: RP procedures (and associated forms, guides, instructions) should be reviewed and modified as necessary to ensure they are compatible with the Refurbishment RP organizational structure, work activities, and radiological conditions. A review of RP procedures will also identify readiness issues that need to be addressed by the RP refurbishment organization.	Johnathon Hash	Jeff Johansson	01-Apr-17	(03 Oct; JJ) N-PROC-RA-0020 "Preliminary Event Notification", was recently revised to accommodate a Notification Protocol for Nuclear Refurbishment Incidents at Nuclear Facilities (under a new section 1.2.5 of the procedure). RMO Action 5894 was derived from Recommendation (e) of NK38-REP-09701-0570560 Appendix I. The recommendation is to review RP Procedures to flag areas where certain references to RP organization and to the Shift Manager to ensure that Refurbishment workers know who to contact in the event of RP events. This review has been performed and the new revision of N-PROC-RA-0020 with the added notification protocol addresses this action. Furthermore, RP has created a Gap Assessment spreadsheet documenting the results of the RP Procedural reviews that was performed internally. This Gap Assessment needs to be assessed to determine what (if any) procedural changes are required. If required, then the changes must be requested via the current process of initiating a DCR in AS7. Programs Section Manager to initiate a review of the Gap Assessment with a target date of 31 Dec 2016 to create any required DCRs. (Nov 9; JJ) Work has started with respect to the review of the gap assessment to identify required changes. (29 Dec; JJ) Gap assessment review I/P. Due date changed to Apr 01, 2017 to accommodate additional time for review.

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5895	In Progress	Readiness Assessment for Hard to Detect Radionulcides	· Sect 8.1: An assessment of the RP's readiness to manage hard to detect hazards should be completed prior to breaker open as well as a follow-up assessment at an appropriate time during the refurbishment.	Johnathon Hash	Jeff Johansson	31-Mar-17	(June 7, JOHANSSON): Explore and plan for a self-assessment (SA) to be performed by an Internal Team (of RP personnel). Ensure an SA entry is initiated in the Self-Assessment database for this deliverable. (Sept 13/2016: JJ) Changed due date from Sept 16 to Oct 15 as additional time is required to schedule and complete the assessment. (19 Oct: JJ) Due date extended to accommodate planning and execution of the assessment. NR RP will plan to have this assessment scheduled to be completed by end of Dec 2016. (23 Nov; JJ) A recent snapshot assessment scope of work performed by BHI (Nov 8-22) was expanded to include the subject of readiness to manage hard to detect radionuclides. This assessment report is currently being prepared and finalized and will be attached herein once completed and issued. Any gaps identified from the assessment will be tracked as actions under Risk #0564. (29 Dec; JJ) BHI draft report was submitted to OPG NRRP for review. Comments were sent back to BHI for disposition and issuance of the final report. (13 Feb; JJ) BHI Final Report has been submitted to OPG follow successful C&D process (see attachment #1 below). OPG is currently reviewing the final report with a view to initiate follow up actions to address the identified gaps and recommendations from the report.

Outage Window	Window Description
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951

Risk to document potential cost for units 3, 1 & 4. - Teledose Infrastructure Mod

EVENT: As a result of the recent CCF 1912 (CCF 1912 - REPLACE BLANK MODULES WITH FIBRE-OPTIC: 2-21130-EP2282) presentation to the CCB, there is a risk that no funding will be available for required AVTS insert modifications for Units 1,3 & 4. CAUSE: CCB only approved modifications funding for Unit 2. IMPACT: No AVTS available for Units 1,3 & 4.

1	Active	Johnathon Hash	Matthew Lai	16-Jan-17	Accept	01-Jul-18	2	2	2	4	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9682	In Progress	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Johnathon Hash	Matthew Lai	08-Nov-17	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification (14 Dec; JJ) Revised "Status = Not Started" to "In Progress".

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3	Active	Johnathon Hash	Jeff Johansson	01-Feb-17	Mitigate	30-Dec-17	3	2	2	6	2	2	2	4

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			5883	In Progress	Darlington Routine Radiation Surveys Instruction Modified to include Unit 2 Refurbishment	· Sect 4.1.1: Modify D-INS-09071-10012, Darlington Routine Radiation Surveys, to expand the routine alpha monitoring program for Unit 2 refurbishment. Moving due date to June 30 in order to capture recommendations from an external report for Hard to Detect Nuclide Monitoring. (7 June, JOHANSSON): moved due date to Aug 31, 2016.	Johnathon Hash	Jeff Johansson	03-Apr-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. (09 Nov; JJ) The highest potential for alpha presence may occur during RFR series work (EF cutting, PT cut, etc...). NRRP ALARA are preparing RFR series specific RPEGs that will include requirements for routine and non-routine alpha surveys/smears. The Darlington Routine Survey instruction will not be revised to incorporate such requirements as it is tracked under the RPEGS. (01 Feb; JJ) DRAFT Routine Survey RPEG has been issued for RP review (see attachment #1). This RPEG was discussed with the Field Section and an action was assigned to the Field Section to determine the level of effort/resources that will take to execute the proposed RPEG surveys.

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			5886	In Progress	Confirm Alpha Counting room for Refurbishment	· Sect 4.1.1: Confirm the availability of a facility for counting alpha contamination samples.	Johnathon Hash	Joe Cicchini	17-Mar-17	(7 June, JOHANSSON): moved due date to Aug 31, 2016. Explore Ryan's suggestion for NR-RP to own and operate the Darlington iSolo counting room, and offer to perform any Darlington RP smears and train their personnel as well. (July 14; JJ): In addition to securing a dedicated alpha counting room for Refurbishment work, it was suggested that HPD perform a QA program for the results by analyzing a fixed percentage of the smears collected and counted, and documenting the results in a QA report for audit purposes. This will be include in the PAS Sampling Policy that is tracked under Action #5880. 25AUG2016 JC - Refurb RP will be working with station RP to develop a smear counting strategy that will benefit both organizations. ***Initiator name changed from BurkeJ to CicchinJ due to Lan ID of burkej not being recognized.
			5887	In Progress	Confirm Monitoring Compliance with Alpha Contamination Limits	· Sect 4.2.1/4.3.1: Confirm through ongoing source term/alpha characterization of Unit 2 that the beta-gamma: alpha activity ratio is greater than 5. This will confirm that pancake and WBM are sufficient to confirm compliance with alpha contamination limits.	Johnathon Hash	Jeff Johansson	30-Sep-17	(7 June; JJ): Consider integrating this requirement into the NR-RP Routine Survey program. If appropriate, close this action to action # 5883. (18 July; JJ): Post June 13 meeting with HPD, a recommendation was made for NR-RP to explore other instruments for Alpha counting (other than iSolos). It was also suggested to have HPD Instrument group involved in this search. (03 Oct; JJ) The recommendation is to confirm through on-going source term and/or alpha characterization studies during refurbishment activities that the beta-gamma: alpha ratio activity is still > 5. Once RFR work commences in unit 2, smears of open system piping/equipment will be performed and analyzed to confirm the ratios are > 5. As per current DNRU2 level 1 schedule, this work will start around July 2017 with window #42 Feeder Removal. Due date for this action has been set to Nov 2017 to confirm the ratios.

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			5890	In Progress	Shielding for WBM at U2 and RWPB	· Sect 4.4.1: Shielding for WBMs at Unit 2 and RWPB should be considered and implemented if the background levels are too high for the monitors to operate effectively. TCD: October 1, 2016	Johnathon Hash	Jeff Johansson	01-Apr-17	(7 June, JJ): This work has started with the shielding considerations for the WBMs/HFFs at the RWPB. The background dose rates in the RWPB are much higher than the required background dose rates for efficient operation of the WBMs/HFFs of <50 micro-Rem/h. Some of the normal operating dose rates in the building are pegged at values > 200 micro-rem/h at locations where the monitors will be located. The Joint-Venture team are performing shielding analysis to determine the required shielding to shield the monitors with (shielding huts and/or walls) to achieve <50 micro-rem/h rates. Various locations within Unit 2 are also being investigated for shielding of the WBMs, like the south wall of the RAB side and close to where the flasks will be lowered from the RMD containing adjusters and vertical flux detectors. It is anticipated that the dose rates from the flask will take the monitors out of service during the craning time of the flasks from elevation 115m down to 100m. (22 Aug; JJ) Shielding requirements for the RWPB monitors (WBM/HFF) are being defined and designed by the JV (see attachments #1,2 & 3 for some emails on the subject). Shielding requirements for Unit 2 monitors are based on local/nearby work that may affect the local background for the monitors. To date, initial discussions have been held with the AA/VFD/HFD Replacement project team (ES Fox) and a walk down of the flask transfer route will be schedule with the project in early Sept. (03 Oct; JJ) Walk down with the ES Fox team working on the AA/VFD/HFD Replacement project was scheduled in Sept but was cancelled due to other priorities. A new walk down meeting needs to be established to walk down the path of flask transfer. RP (Jeff J) is set up a new meeting with ES Fox. (TCD: 31 Oct) (09 Nov; JJ) Walk down of the area has identified that the craning/staging area for the AA/VFD flasks is located at column line K16 - L16. The south bank of whole body monitors is located at column line A16 - B1

5694	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management	Event: There is a risk that Nuclear Refurbishment employees or Contractors may be exposed to unexpected radionuclide(s) which may lead to significant dose assignment. Cause: Inadequate source term characterization leading to radiological work planning, protective actions and dosimetry requirements not properly identified to protect workers from the hazards present. Impact: This may potentially result in high doses that could exceed OPG dose limits or CNSC Dose limits, as well as a disruption to Nuclear Refurbishment work. Regulatory, public and union relations issues would be very problematic and would be amplified by the fact that Bruce Power had the same type of event during their refurbishment.	5891	In Progress	Contamination Control Intiatives for RFR, RWPD and SGs	· Sect 5.1: RP should review in detail the refurbishment work (e.g., CWPs for RFR in vault and RWPB, and SG work) for opportunities to reduce and control contamination spread and protection of workers against internal hazards. The outcome of this review should be documented and communicated to the Field group, HP assessors, project leaders, and REP preparers. The output from this review should be incorporated in the CWPs.	Johnathon Hash	Joe Cicchini	17-Mar-17	(June 7, JOHANSSON) Action assigned to the Field Support Section. 25AUG2016 - Initiator name changed from burkej to cicchinj due to burkej not be recognized as a lan ID
			5892	In Progress	Contamination Control Equipment	· Sect 5.1: Confirm who is procuring/deploying/controlling contamination control equipment (e.g., vacuum cleaners with HEPA filters) for all refurbishment projects (e.g., RFR, SG, and BOP work). Met with external vendor to confirm scope of purchased services regarding Munter. External review commissioned for review of recommendations for HEPA use on the project.	Johnathon Hash	Joe Cicchini	17-Mar-17	23 Feb. 16 A list of contamination control equipment and the TCD for arrival of the equipment on site has been requested of RFR. A list of contamination control equipment for Balance of Plant and SG work has been requested. All other information remains unchanged. The ownership for procurement/deployment and control of contamination control equipment among the Projects is under investigation. RFR has indicated that they are responsible for procurement of five (5) smooth bore hose Hepa vacuum cleaners; 2 - for the reactor vault, 1 for the reactor auxilliary bay and 2 for the RWPB. Arrangements will be made to assist RFR with the deployment and control of the vacuums as per the Radiation Protection Coordinator assigned to the specific task. Ownership of contamination control equipment for Balance of Plant and SG work is currently in progress and an update will be provided before 23 Feb. 2106. It has been determined that the Radiation Protection work group does not have ownership for procurement of additional contamination control equipment. The Radiation Protection department will assist with the deployment and control of "contaminated" equipment used on the projects under the guidance of the Radiation Protection Coordinators. RP may consider purchase of some equipment. Currently no CCF has been initiated however it is under review. (09 Aug; JJ) Due date changed to Sept 30, 2016. 25AUG2016 JC - A comparison between OPG sites has been initiated to develop a fleet approach to CATS devices. This exercise will produce a program that will enhance our contamination control strategy

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			5894	In Progress	Procedure Review and Update as Required for Refurbishment	· Sect 7.1: RP procedures (and associated forms, guides, instructions) should be reviewed and modified as necessary to ensure they are compatible with the Refurbishment RP organizational structure, work activities, and radiological conditions. A review of RP procedures will also identify readiness issues that need to be addressed by the RP refurbishment organization.	Johnathon Hash	Jeff Johansson	01-Apr-17	(03 Oct; JJ) N-PROC-RA-0020 "Preliminary Event Notification", was recently revised to accommodate a Notification Protocol for Nuclear Refurbishment Incidents at Nuclear Facilities (under a new section 1.2.5 of the procedure). RMO Action 5894 was derived from Recommendation (e) of NK38-REP-09701-0570560 Appendix I. The recommendation is to review RP Procedures to flag areas where certain references to RP organization and to the Shift Manager to ensure that Refurbishment workers know who to contact in the event of RP events. This review has been performed and the new revision of N-PROC-RA-0020 with the added notification protocol addresses this action. Furthermore, RP has created a Gap Assessment spreadsheet documenting the results of the RP Procedural reviews that was performed internally. This Gap Assessment needs to be assessed to determine what (if any) procedural changes are required. If required, then the changes must be requested via the current process of initiating a DCR in AS7. Programs Section Manager to initiate a review of the Gap Assessment with a target date of 31 Dec 2016 to create any required DCRs. (Nov 9; JJ) Work has started with respect to the review of the gap assessment to identify required changes. (29 Dec; JJ) Gap assessment review I/P. Due date changed to Apr 01, 2017 to accommodate additional time for review.

564

Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization and Management

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5895	In Progress	Readiness Assessment for Hard to Detect Radionulcides	· Sect 8.1: An assessment of the RP's readiness to manage hard to detect hazards should be completed prior to breaker open as well as a follow-up assessment at an appropriate time during the refurbishment.	Johnathon Hash	Jeff Johansson	31-Mar-17	(June 7, JOHANSSON): Explore and plan for a self-assessment (SA) to be performed by an Internal Team (of RP personnel). Ensure an SA entry is initiated in the Self-Assessment database for this deliverable. (Sept 13/2016: JJ) Changed due date from Sept 16 to Oct 15 as additional time is required to schedule and complete the assessment. (19 Oct: JJ) Due date extended to accommodate planning and execution of the assessment. NR RP will plan to have this assessment scheduled to be completed by end of Dec 2016. (23 Nov; JJ) A recent snapshot assessment scope of work performed by BHI (Nov 8-22) was expanded to include the subject of readiness to manage hard to detect radionuclides. This assessment report is currently being prepared and finalized and will be attached herein once completed and issued. Any gaps identified from the assessment will be tracked as actions under Risk #0564. (29 Dec; JJ) BHI draft report was submitted to OPG NRRP for review. Comments were sent back to BHI for disposition and issuance of the final report. (13 Feb; JJ) BHI Final Report has been submitted to OPG follow successful C&D process (see attachment #1 below). OPG is currently reviewing the final report with a view to initiate follow up actions to address the identified gaps and recommendations from the report.

Outage Window	Window Description
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951

Risk to document potential cost for units 3, 1 & 4. - Teledose Infrastructure Mod

EVENT: As a result of the recent CCF 1912 (CCF 1912 - REPLACE BLANK MODULES WITH FIBRE-OPTIC: 2-21130-EP2282) presentation to the CCB, there is a risk that no funding will be available for required AVTS insert modifications for Units 1,3 & 4. CAUSE: CCB only approved modifications funding for Unit 2. IMPACT: No AVTS available for Units 1,3 & 4.

1	Active	Johnathon Hash	Matthew Lai	16-Jan-17	Accept	01-Jul-18	2	2	2	4	1	1	1	1

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9682	In Progress	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification	Johnathon Hash	Matthew Lai	08-Nov-17	Send CCF to CCB for RQE increase for U1/3/4 EP2282 Modification (14 Dec; JJ) Revised "Status = Not Started" to "In Progress".

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718

The Cyclic Maintenance budget may not have enough funds (Labour & Materials) to cover Shutdown Maintenance Backlog

Event: An independant review of the Cyclic Maintenance Budget confirmed there will be a shortfall of funds assigned to the D1621 work Program associated with Shutdown Maintenance cyclic work orders. This work is part of the Equipment Reliability Index target that will be committed to for the return to service of Unit 2. Cause: Initial budget assigned to cyclical overflow was estimated at $78M per unit. Present budget is $34M. Estimates received to date from Vendors are totaling $51M. Potential impact: Shortfall of funds impacting RTS of unit 2. station meeting ongoing on how to divide work and budget to ensure work is completed.

3	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Mitigate	15-Oct-19	5	2	3	15	3	2	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7955	In Progress	Shortfall of funds for mtce can affect RTS of U2.	Shortfall of funds impacting RTS of unit 2. station meeting ongoing on how to divide work and budget to ensure work is completed.	Val Bevacqua	Tom Carvin	16-Aug-19	UPDATE 20SEPT2016 per Val Bevacqua This is a risk that must remain open as it deals with discovery. Place the completion date out to 2019. Val Bevacqua Updated 8/5/2016 contingency funds have been allocated to support the maintenance organization.

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ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

677	Availability of DN Authorized Staff for Station and Refurb Support	Event: Insufficient authorized staff (certified Authorized Nuclear Operator (ANO), Control Room Shift Supervisors (CRSS) and Shift Managers (SM)) staff (2013-2017) and Non-Licensed Operator (NLO) staff (2013 >2020) to support Operations (outage, On-Line work (IPG), Emergent Work (FIN), procedures, training) and Refurbishment planning and execution. Causes: 1) Attrition due to retirements of ANO, CRSS/SM, NLO and Authorized Training Staff (ATS) due to demographic pool. 2) ANO initial training program throughput has historically been lower than the 60.0% previously assumed. 3) CRSS initial training previously have not been successful in producing new candidates for two (2) consecutive groups. 4) Lack of Authorization Training program-ready candidates has resulted in 40% to 50% smaller than Business Plan class sizes causing refloat to NR OM&A budget for ANOITs. 5) Knowledge gap between NLO and ANO In Training (ANOIT) results in lower entry calibre. 6) Shortages in Authorized Training Staff (ATS) to support ANO recovery plan needs. The risk is compounded by a high reliance on augmented staff to support a recovery plan and operate the business. Impact: This has the potential to impact on refurbishment planning and execution, Unit outages and VBO durations, efficiency of FIN and IPG, support for Authorization Training and backlogs in Ops Procedure.	4	Active	Boris Vulanovic	Ross Mccord	28-Feb-17	Mitigate	02-Apr-17	5	1	2	10	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									
			9964	Draft	Monitoring Transition Plan Initiatives related to Authorized Staff Resources	The latest strategies for this risk mitigation involves several initiatives being put into play that will assist in meeting short term goals in keeping the work flowing until sufficient authorized staff are available to staff the refurb. department as per the Transition Plan. these initiatives are as follows 1) Reduce ANO minimum scheduled compliment to 7 from the current 8. This will allow 3 ANO's to be transferred to the refurb project (negotiated with the station). Additionally this will focus the duty crew on completing the co piloting of the 5 new ANOIT's in a timely fashion as it creates an urgency that would not otherwise exist allowing for a protracted co pilot period. This action is to take place in the first week of Jan 2017 2) Complete the co piloting of 4 SSIT's (TCD end of March 2017). This will free up 4 CRSS's to fill the need in the refurb organization. Additionally this will allow current CRSS's to co pilot in the SM position 3) For the upcoming work load peak created by the early completion of the defuel program the station has agreed to deploy the SDQ (special duty qual) NO's from the defuel campaign to the refurb project. Effectively this augments the A-E refurb shift crew by 2 NO's per crew or 10 NO's total. 4) as a stop gap measure Refurb has obtained 2 year contract extension for 6 of it's previously authorized personnel. This will secure our ability to support the review and approval of vendor documentation. 5) DORT / NORT meetings continue on a regular basis. These meeting provide a form for assigning / dividing available resources both licensed and non licensed to ensure station and refurb priorities are met	Boris Vulanovic	Michael O'dowd	20-Mar-17								
			Outage Window		**Window Description**														
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699	Foreign Material Management in Heat Transport System Leading to fuel defect	Cause A significant fuel defect rate in the two refurbished units at Bruce has been reported, which was caused by Debris (from unknown source) Event Remove defect fuel bundles (> 25 fuel bundles based on Bruce Power and Pt. Lepreau OPEX), Impact Potential Stoppage/Delay in HTS RTS Commissioning, and may require mini-outage after NR start-up. It can potentially impact station capacity factor, and not meeting CNSC/OP&P requirements of iodine concentration.	3	Active	Val Bevacqua	Jim Robertson	29-Dec-16	Mitigate	15-Oct-15	3	1	3	9	1	1	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									

699	Foreign Material Management in Heat Transport System Leading to fuel defect	Cause A significant fuel defect rate in the two refurbished units at Bruce has been reported, which was caused by Debris (from unknown source) Event Remove defect fuel bundles (> 25 fuel bundles based on Bruce Power and Pt. Lepreau OPEX), Impact Potential Stoppage/Delay in HTS RTS Commissioning, and may require mini-outage after NR start-up. It can potentially impact station capacity factor, and not meeting CNSC/OP&P requirements of iodine concentration.	8826	In Progress	Flush Strainer Progress	Level 1 with all the timelines of the mods is required next week. Complete Determine the need date and work backwards. Develop the plan based on backward planning. Complete Review the plan on Friday - Aug.12, 2016. Complete Next deliverable Conceptual Design is Dec 30/216. ***** Updated following Issues Meeting on 06Feb2017 ****** The conceptual design report was issued and accepted from CEI. This item is also being tracked in Issue # 342 1) Schedule SIM for team on the status of the top design options.2) Prepare for an Executive Options Review Board Meeting (March 15)	Steve Goodchild	Mario Campigotto	15-Mar-17	Heat Transport Filtration/Strainer Design: (Prepared by: Andrew Jeffery) 3 Oct 2016 A Heat Transport Filtration/Strainer Design is to be developed to mitigate risk and help protect the fuel and pressure tubes from debris. · Prepare Engineering Needs Document for Heat Transport Filter/Strainer Design (Complete, NK38-NR-REP-33000-00001 issued; ECR 24638 Approved) · Arrange Staffing Resources for HTS RTS Project (Complete) o Interim Project Manager – Ron McKibbon; MTL – Imran Malik; Interim DTL – Ali Azarbad o Additional DTL & PM interviews are on-going · Kick-Off Meeting for HTS RTS Filter/Straining Strategy – Conceptual Design (Complete as scheduled) · Preparation of Needs Document to support Chemical Addition & Monitoring Skid for Hot Conditioning (Delayed for other project support; Revised Target of Oct 10th, Owner – System Eng) · Preparation of Needs Document to support Pressurizing Skid for Operational Leak Test (Delayed for other project support; Revised Target of Oct 10th, Owner – System Eng) · Develop Design EC Level 1 for HTS RTS Modifications (30 SeptemberTBD) · Investigate waste strategy for removed debris, filters, etc (10 October) · Top Priority à Secure contract and initiate Conceptual Design phase (Contract in place: October 21; CDR complete: December 30th o Prepare Sole Source Justification for qualified vendor (MTL, Supply Chain support needed to expedite contract paperwork) o Arrange Supply Chain support (TCD: Oct 6th)

699	Foreign Material Management in Heat Transport System Leading to fuel defect	Cause A significant fuel defect rate in the two refurbished units at Bruce has been reported, which was caused by Debris (from unknown source) Event Remove defect fuel bundles (> 25 fuel bundles based on Bruce Power and Pt. Lepreau OPEX), Impact Potential Stoppage/Delay in HTS RTS Commissioning, and may require mini-outage after NR start-up. It can potentially impact station capacity factor, and not meeting CNSC/OP&P requirements of iodine concentration.	9677	In Progress	Develop and implement FME enhancements to mitiage impact on fuel and major components during Refurbishment	Develop and implement FME enhancement requirements for refurbishment work deemed to have a potential impact on fuel and pressure tube integrity. Implement refurbishment specific enhancements into FME governance. Training and gap analysis (of work packages / FME plans already approved) is required to ensure enhancements are applied.	Val Bevacqua	Brian Barclay	14-Apr-17	Enhanced Foreign Material Exclusion Program: The enhanced foreign material exclusion program has developed recommendations and specifications with respect to chemistry (NK38-SPEC-09701-10035) and foreign material (NK38-NR-REP-33100-10007) cleanliness during heat transport maintenance. This is to be incorporated into a Darlington instruction and distributed through the project bundles and vendors. - Incorporate enhanced foreign material recommendations into actionable document (FME INS) – (Rev 001 Issued – NK38-INS-09701-10010, Rev 002 to be issued 12-Dec-16 with minor clarifications) - Two memorandums (NK38-CORR-33000-0614895; NK38-CORR-33000-0614924) detailing HTS Fitness for Service Sufficiency Requirements with respect to FME and Hot Conditioning. – (TCD: Sr. Manager Approvals in Progress) - Completion of Change Management Plan (per N-STD-AS-0024; SPOC: Mike McDonald) - Discussion with Program Owner & Stakeholders – Maintenance, Engineering, Chemistry (Complete) - Gap Analysis of Current FME practices and Enhanced FME expectations for Refurb (INITIATED, TCD 23-Dec-16) - Training Needs Analysis (TCD: Nov 4, 2016) (COMPLETE) – Training Table Top session Completed – Development of Training Content IN PROGRESS. - Incorporation of Chemistry Specification and HTS FME D-Instruction into FME Program Governance (Revision of N-PROC-MA-0018 to be issued 15-Dec-16) – As per Change Management Plan (Plan approval Nov 9, 2016) - Communication of revised FME Program Expectations for Refurbishment including applicable training (Jan 15, 2017) - Implementation of enhanced FME into refurbishment work packages, vendor training, along with OPG oversight checkpoints - FME implementation plan to be developed (COMPLETE) Change notifications have been sent to all vendors as well as training bulletin. BWXT is the only vendor to formally respond as of Feb 15, 2017. Contract Manager Enhanced FME Memo Sent to Vendor (Y/N)? Response Recei

Outage Window	Window Description
084	084 - Fuel Load
093	093 - Low Power Testing & Heat-up

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

820	Discovery work arising from valve replacements	The risk is that there is a large amount of discovery work encountered in the valve replacement program resulting in cost impacts and schedule delays to the planned valve replacement schedule. This is caused by limitations in the ability to examine/inspect valves internals prior to refurbishments and OPEX from previous refurbishment projects.	1	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Monitor	28-Jun-18	3	3	1	9	3	3	1	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8398	In Progress	U2 Power Supply Management - Develop a Strategy	Develop a strategy to manage power supply and demand in U2 For the duration of the U2 outage and present the strategy at an ORB FOAK Challenge Meeting.	Val Bevacqua	Tom Carvin	03-Apr-17	March 06/17 Maintenance is completing update meeting with all contract partners to provide details of the Temporary power process. Maintenance has actioned engineering to review the overload trip setting on 4001 & 4002 500kVa transformers Feb 17/17 Refurb maintenance has completed a plan to manage the U2 Temporary power supply and demand. This plan calls for Status control Tags to be affixed to each 600 RE. An email box is being setup to accept request for usage of the RE's. Refurb Maintenance is scheduled to deliver and update to the Thursday Feb 23 Pillar meeting. A strategy is being developed to manage the U2 power supply and demand. Refurb maintenance is the owner. Refurb maintenance has appointed a SPOC to manage the initiative Nov 10/16 Worley Parson has been tasked with developing a strategy to manage power supplies. The strategy plan is progressing and will be turned over to OPG Refurb maintenance to execute. Dec 8/16 Refurb maintenance has met with Worley Parson to start the process of turning over the U2 Temporary power supply program to maintenance.

Outage Window	Window Description
000	000 – No Window Related

870	Augmented Staff Rules puts future refurbishment units at RISK due to lack of budget needed to compensate for additional turnovers	Event: the Augmented Staff Contract duration. Max for outside contractor is 5 yrs 3 Yrs. Max for OPG rehire is 2 years. We are supporting a 10 yr project. Each unit takes 3 years. This was undated in NOV2016 due to the new Aug staff rules on contracts having even shorter durations. Current Probability changed to 4 due to this Aug staff change. Cause: The Auditor General applied restriction for contractors working at OPG. Impact : If we cant keep contractors beyond these durations all the way through refurbishment we will be starting over with new talent constantly repeating lessons learned. We cant even finish one unit with the same people that started. Path Forward - plan over lap Augstaff contracts to ensure scope of work is turnover to the next contractor and look at opportunities to hire full time instead of contracts. Based on this new direction the RISK score has been minimized for management to plan ahead to ensure these risks don't materialize. Impact 2: This will definitely increase everyone's budget (overlap of contracts every 2 years) who is using Aug staff to fill a need for this incremental project. Example: a 3 month overlap every two years on a 12 year project, is equal to 6 turnovers needed =18 months of additional funding for each role that is needed for the life of Refurbishment. @ $100.00/hour X 18 Months = $280,000.00 additional funding for each role that lasts the life of refurbishment. NR O&M Technical Procedures has RISK 767 for additional funding.	2	Active	Boris Vulanovic	Paul Davies	11-Jan-17	Monitor	07-Dec-18	4	2	1	8	4	2	1	8

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

812	Layup can have a significant impact on station environmental release limits delaying layup activities	EVENT: Layup can impact station environmental release limits.CAUSE: We are draining and drying more systems/volumes than normal (such as the SGs, PHT, Conventional side and Moderator system)IMPACT: Delay in schedule.		Active	Roger Daly	Ray Kissel	10-Jan-17	Monitor	30-Jun-17	2	3	3	6	2	3	3	6

Outage Window	Window Description
002	002 - Conventional Side Layup
003	003 - Secondary Side SG Layup
013	013 - PHT Bulk Drain (Includes V42 Mod)
029	029 - HTS Vac Dry
034	034 - Primary Side SG Layup
035	035 - HTS Aux Dry
038	038 - Moderator Drained & Flush
048	048 - HTS Aux Drain,Purge,Outside Vault

There are no Draft, Not Started, In Progress Actions associated with the risk.

724	Chemistry Control Procedural Review Risk	Event: Due to a short period of time from design been complete (Aug 2015) and where required documentation (Chemistry Control OM and Chemistry Lab Procedures) is needed (Aug 2016) the completed documentation being ready in time is at risk. Also, there will be required reviews on O&M documentation during the same time frame. This will be a challenge for Chemistry Department based on present resources and therefore putting deliverables been ready for breaker open at risk. Cause : NR design documentation is scheduled for issued for all projects at the same time. Potential impacts : Chemistry Control documentation preparation may be late affecting chemistry control during initial stage of layup.	2	Active	Roger Daly	Sergei Voitchenko	28-Feb-17	Mitigate	30-Nov-16	5	1	1	5	3	1	1	3

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

708	Materials budget for emergent broke-fix maintenance and scope growth during Shutdown, Layup and Runup is not included in MTCE budget.	Event: Materials required for broke-fix maintenance and scope growth during Shutdown, Layup and Run up Phases is not in MTCE Budget Cause: Contingecy funds not included in business planning process Potential impacts: Unable to repair, required for start up equipment, affecting critical path duration. 1. From Scope Freeze to Breaker Open: For the purpose of calculating the contingency for this specific risk, we assume, based on station IPG scope growth history, that there will scope growth between each Unit WO scope freeze and breaker open. Based on DNGS IPG history, 1-2 work orders are added to scope per day. The added work is then scheduled in the online schedule (not necessary FIN work to be executed immediately). It is expected that much of the work added during this period would be executed by DNGS IPG, however, some scope may be added to D1621 scope and executed during the outage proper. This type of 'cyclic' backlog scope will occur over a period of 16 months for each unit. We are estimating that, of the identified work during unit operation during this time period, 1 WO per week will actually be accepted into B/O-B/C scope. That equates to 64 new work orders. We assume a cost per work order of $6,000 average per work order. In total, this calculates to $400,000 per unit. ($1.6 million for overall Program). 2. From Breaker Open to Breaker Closed: For the purpose of calculating the contingency for this specific risk, we assume, based on station outage history, that there will be an average of 4 work orders per day of the outage, reviewed and approved for new scope, from breaker open to breaker closed. At Scope Freeze for D1621 and DNRU2, the D1621 WO # was 5,498. At 4 new WO per day, at ~1100 days, equals 4,400 work orders. We assume a cost per work order of $6,000 average per work order. In total, this calculates to $26 million per unit ($104 million for overall Program).	2	Active	Boris Vulanovic	Val Bevacqua	29-Dec-16	Monitor	16-Aug-19	2	2	2	4	2	2	2	4

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
7955	In Progress	Shortfall of funds for mtce can affect RTS of U2.	Shortfall of funds impacting RTS of unit 2. station meeting ongoing on how to divide work and budget to ensure work is completed.	Val Bevacqua	Tom Carvin	16-Aug-19	UPDATE 20SEPT2016 per Val Bevacqua This is a risk that must remain open as it deals with discovery. Place the completion date out to 2019. Val Bevacqua Updated 8/5/2016 contingency funds have been allocated to support the maintenance organization.

Outage Window	Window Description
000	000 – No Window Related

767	O&M Procedure Update Program may not have sufficient Funding	Event: Budget estimate for procedure work was estimated to cost around 42 million. this was based on opex from Bruce Power and Point Lepreau. Cause: Estimate was challenged and reduced down to 32 million. Impact: Could cost an addtional 10 million dollars to complete the program.	2	Active	Boris Vulanovic	Mike Dance	11-Jan-17	Accept	03-Oct-16	3	1	1	3	3	1	1	3

Outage Window	Window Description
000	000 – No Window Related

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

706	Present ERT mincomp plan does not accommodate for and Islanded Unit while meeting adequate response time to emergent events	Event: DN Refurbishment organization is oblidged to comply with fire protection regulatory standards. Darlington's present ERT mincomp plan does not accommodate for and Islanded Unit while meeting adequate response time for potential emergent issues. Cause: A safety event that required ERT to respond either on Islanded Unit or Station. Other work requiring ERT to respond in the event of an emergency will be required to stop until ERT able to respond. eg, hot work, high angle rescue, confined space Potential impact: All work requiring ERM response to safety issue will stop if ERMs are required to attend to another event	1	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Monitor	15-Aug-19	1	1	2	2	1	1	2	2
			Outage Window		**Window Description**														
			083		083 - Lower Feeder Installation														
			118		118 - CT Install Series														
			119		119 - Fuel Channel Install Series														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
728	Acute Tritium releases during NR primary side drain and dry operations	Event: Potential to have an acute Tritium Emission that exceeds the Station Internal Investigation Limit (IIL) for tritium emissions during the NR Outage, particularly during Moderator and Heat Transport draining and drying steps. Cause: -High tritium inventory in Moderator System, ineffective drying capacity from skids, poor condition of Vault Vapor Recovery Dryers or insufficient focuson Spills and Leaks. Potential Impacts: - Could delay work due to driers or skids needing regeneration. -Unfavorable Public Relations if high emissions persist and if insufficient preparation done ahead of time to mitigate.	2	Active	Roger Daly	Lillian Yiu	28-Feb-17	Monitor	31-Mar-17	2	1	1	2	2	1	1	2
			Outage Window		**Window Description**														
			000		000 – No Window Related														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
859	Unit Temporary Power System	Event: Currently this is no plan in place to control the allocation of power from the newly installed temporary power distribution system. In past outages, there has been a SPOC assigned from the station to control distribution (MC). This needs to be considered. Background Information: Unit temp power distribution system being installed by Shutdown Layup has 12 power carts located across unit. Install and remove only under po. No one is coordinated usage during execution when supplies will be lost to class 4 cyclic mtce. Also no one is coordinating usage to prevent overloading and conflicts between venders on how has priority. Also no one assigned to move cables when outages occurring.	3	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Monitor	15-Dec-16	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**														
			041		041 - Class 3 Electrical Maintenance														
			051		051 - Class 4 Electrical Maintenance														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
874	Refurbishment Maintenance - Milestone OP2170 S2,3,4 PC1 All PC1 Prepared At risk	A review of the work list found the following tasks flagged for permit: Segment 2 : 1625, Segment 3 : 421, Segment 4 : 472 for a total 2518 tasks for permitry. For segment 1, Refurb maintenance did not meet the milestone. There were 698 tasks in segment 1 which resulted in 265 PC1's. Given this ~ 3 to 1 ratio it is predicted maintenance will need to submit ~840 PC1's to meet the milestone.	3	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Monitor	15-Oct-19	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**														
			000		000 – No Window Related														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																

Program: Operations and Maintenance - 10000

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.		Active	Boris Vulanovic	Gary Leach	28-Feb-17	Mitigate	31-Jul-17	3	1	4	12	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	**1308**	In Progress	Commissioning Engineer resource profile	Review commissioning engineer resource profile and mitigate through contract staff hires if required. AR#28148291-01 Review commissioning engineer resource profile TCD:2017/01/15	Gary Leach	Steve Goodchild	14-Apr-17	12-JAN-2017 *** Update provided by Steve Goodchild **** Current strategy has been to develop the Engineering RTS Section with 6 staff of which 4 have arrived. The intent being that the system responsible staff in other sections will provide the support required for the commissioning activities. This strategy, based on previous OPEX may be challenged as the RTS group will be in more of a coordination role. The action is extended to allow for the current strategy to be further developed. _____ Update Sept 14/2016: Added Steve Goodchild as delegate to support with engineering resources. An engineering team to support commissioning and return to service has been formed. This group will support planning and execution of refurbishment and projects and modification work. ********** swim lane diagragm developed to identify activities required by functional engineering, resourcing for RTS activities as per the swim lane diagragm will be compared to projected resource profiles. Given the likelihood of resource issue the probability score has increased thus increasing the risk score to 9. Owner changed from D. Somerville to G. Leach by A. Kalafatis 2015/04/30 to align with AR assignment Initiator changed to M. Stewart, review in progress and staffing plans being developed.
			7539	In Progress	Produce a L3 RTS plan	Produce a L3 schedule of RTS activities in the schedule and ensure resource requirements are tallied for operations, maintenance, chemistry, environment, radiation protection, engineering and our vendor support. This will be used to compare to our current levels of staffing during these evolutions. Any gaps will be addressed by increasing staffing levels to the required numbers through staff movements to shift, additional staff from the station and the fleet or movement of the evolutions on the schedule if applicable. These options will be reviewed and concurred to by O&M, Eng and Work Control.	Gary Leach	Aris Kalafatis	14-Jul-17	Update Sept 14/2016: S2B/3/4 assessing milestone has been moved to June of 2017. A level 3 schedule will follow this milestone. Due date moved to a month after assessing to allow quality review and analysis of resources required. Review of the approved schedule to start following REV C issuance on June 17.
			7540	Not Started	Explore the need for EFIN/FIN during RTS	During RTS the critical path is affected by break plan discovery work that is not on the schedule. The work control process is not adequate to resolve these issues and maintain schedule integrity. Use of a FIN (fix it now) and EFIN (engineering) teams needs to be explored to see if staffing and funding can be achieved.	Gary Leach		30-Sep-17	June 15/16 - meetings with engineering and maintenance to be set up following Rev C issuance to discuss the possible use of these teams. Jan 5, 2017 - date extended to after assessing complete for RTS.
			7543	In Progress	Related to RTS prerequisites - ensure that PM's are planned & completed on critical instrumentation, NV's, etc, prior to start-up	FIAW/FOAK review board requested a review of RTS planning to ensure that required PM's on critical equipment are scheduled to ensure they do not delay start up activities. As an example, does the GCR RTS have the required activities planned to ensure it is available prior to being required.	Gary Leach	Aris Kalafatis	12-Jun-17	As part of the RTS logic reviews being completed these actions are being checked. Final reviews are to be completed by June 12/2017 to allow assessing. Date changed to reflect this date.

Outage Window	**Window Description**
000	000 – No Window Related
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	093	093 - Low Power Testing & Heat-up
			094	094 - Power Escalation
			095	095 - Run-up & Sync
			096	096 - High Power Testing & Turbine Testing
			193	193 - Heat-up & Hot Condition

894	Managing the project with operations processes versus construction processes	There is a risk of schedule delays and cost increases resulting from not adjusting the processes used to get work done to allow for construction efficiencies when systems and components on the refurbishment units are isolated from the operating plant. Every effort should be made to bring these opportunities to light and utilize them when it's proven to ensure the safety and quality of NR projects and ensure safe return to service of unit 2.	3	Active	Ken Gilbert		29-Dec-16	Mitigate	30-Sep-16	4	3	3	12	2	2	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			9625	In Progress	Revise operating documents to reflect refurbishment unit OP&P	Revise operating documents to reflect refurbishment unit OP&P to remove unnecessary constraints and restrictions when in State 3A and 3B - GSS: operating procedures to eliminate unnecessary work restrictions in State 3A and 3B - Heat sinks: operating procedures to eliminate unnecessary work practices in State 3A and 3B- Airlocks: operating procedures to support opening airlock doors to allow efficient vault access	Ken Gilbert		31-Mar-17								
			9643	In Progress	Revise Nuclear Governance associated with work-site proced	Revise Nuclear Governance associated with work-site procedure markups to support Vendor procedures	Ken Gilbert		31-Jan-17								
			9644	In Progress	Relaxing constraints for Refurb	Relaxing constraints for Refurb unit steam doors	Ken Gilbert		31-Mar-17								
			9645	In Progress	Finalize work program initiatives	Finalize work program initiatives and prioritize efficiency improvements for 2017 Q1 and Q2	Ken Gilbert		31-Jan-17								
			Outage Window		**Window Description**												
			000		000 – No Window Related												

900	U2EE Assumption 882 - Scope re-classification from NR to DO	Event: Risk is that assumption 882 pertaining to reclassification of scope during U2EE from NR to DO may be not materialize. Cause: Inconclusive assumption may result in DO being over and NR being underspend. Impact: Assumption 882 re-classifies NR scope to DO, resulting in reduction of NR and increment in DO budget.	2	Active	Val Bevacqua	Tom Carvin	29-Dec-16	Monitor	15-Feb-17	3	3	3	9	3	3	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

Program: Operations and Maintenance - 73023

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.		Active	Boris Vulanovic	Gary Leach	28-Feb-17	Mitigate	31-Jul-17	3	1	4	12	2	1	2	4
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000	000 – No Window Related
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	093	093 - Low Power Testing & Heat-up
			094	094 - Power Escalation
			095	095 - Run-up & Sync
			096	096 - High Power Testing & Turbine Testing
			193	193 - Heat-up & Hot Condition

Program: Operations and Maintenance - 73028

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.		Active	Boris Vulanovic	Gary Leach	28-Feb-17	Mitigate	31-Jul-17	3	1	4	12	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			1308	In Progress	Commissioning Engineer resource profile	Review commissioning engineer resource profile and mitigate through contract staff hires if required. AR#28148291-01 Review commissioning engineer resource profile TCD:2017/01/15	Gary Leach	Steve Goodchild	14-Apr-17	12-JAN-2017 *** Update provided by Steve Goodchild **** Current strategy has been to develop the Engineering RTS Section with 6 staff of which 4 have arrived. The intent being that the system responsible staff in other sections will provide the support required for the commissioning activities. This strategy, based on previous OPEX may be challenged as the RTS group will be in more of a coordination role. The action is extended to allow for the current strategy to be further developed. --- Update Sept 14/2016: Added Steve Goodchild as delegate to support with engineering resources. An engineering team to support commissioning and return to service has been formed. This group will support planning and execution of refurbishment and projects and modification work. ********** swim lane diagragm developed to identify activities required by functional engineering, resourcing for RTS activities as per the swim lane diagragm will be compared to projected resource profiles. Given the likelihood of resource issue the probability score has increased thus increasing the risk score to 9. Owner changed from D. Somerville to G. Leach by A. Kalafatis 2015/04/30 to align with AR assignment Initiator changed to M. Stewart, review in progress and staffing plans being developed.							
			7539	In Progress	Produce a L3 RTS plan	Produce a L3 schedule of RTS activities in the schedule and ensure resource requirements are tallied for operations, maintenance, chemistry, environment, radiation protection, engineering and our vendor support. This will be used to compare to our current levels of staffing during these evolutions. Any gaps will be addressed by increasing staffing levels to the required numbers through staff movements to shift, additional staff from the station and the fleet or movement of the evolutions on the schedule if applicable. These options will be reviewed and concurred to by O&M, Eng and Work Control.	Gary Leach	Aris Kalafatis	14-Jul-17	Update Sept 14/2016: S2B/3/4 assessing milestone has been moved to June of 2017. A level 3 schedule will follow this milestone. Due date moved to a month after assessing to allow quality review and analysis of resources required. Review of the approved schedule to start following REV C issuance on June 17.							

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	7540	Not Started	Explore the need for EFIN/FIN during RTS	During RTS the critical path is affected by break plan discovery work that is not on the schedule. The work control process is not adequate to resolve these issues and maintain schedule integrity. Use of a FIN (fix it now) and EFIN (engineering) teams needs to be explored to see if staffing and funding can be achieved.	Gary Leach		30-Sep-17	June 15/16 - meetings with engineering and maintenance to be set up following Rev C issuance to discuss the possible use of these teams. Jan 5, 2017 - date extended to after assessing complete for RTS.
			7543	In Progress	Related to RTS prerequisites - ensure that PM's are planned & completed on critical instrumentation, NV's, etc, prior to start-up	FIAW/FOAK review board requested a review of RTS planning to ensure that required PM's on critical equipment are scheduled to ensure they do not delay start up activities. As an example, does the GCR RTS have the required activities planned to ensure it is available prior to being required.	Gary Leach	Aris Kalafatis	12-Jun-17	As part of the RTS logic reviews being completed these actions are being checked. Final reviews are to be completed by June 12/2017 to allow assessing. Date changed to reflect this date.

Outage Window	Window Description
000	000 – No Window Related
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC
093	093 - Low Power Testing & Heat-up
094	094 - Power Escalation
095	095 - Run-up & Sync
096	096 - High Power Testing & Turbine Testing
193	193 - Heat-up & Hot Condition

Program: Operations and Maintenance - 73062

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.		Active	Boris Vulanovic	Gary Leach	28-Feb-17	Mitigate	31-Jul-17	3	1	4	12	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	**1308**	In Progress	Commissioning Engineer resource profile	Review commissioning engineer resource profile and mitigate through contract staff hires if required. AR#28148291-01 Review commissioning engineer resource profile TCD:2017/01/15	Gary Leach	Steve Goodchild	14-Apr-17	12-JAN-2017 *** Update provided by Steve Goodchild **** Current strategy has been to develop the Engineering RTS Section with 6 staff of which 4 have arrived. The intent being that the system responsible staff in other sections will provide the support required for the commissioning activities. This strategy, based on previous OPEX may be challenged as the RTS group will be in more of a coordination role. The action is extended to allow for the current strategy to be further developed. _____ Update Sept 14/2016: Added Steve Goodchild as delegate to support with engineering resources. An engineering team to support commissioning and return to service has been formed. This group will support planning and execution of refurbishment and projects and modification work. ********** swim lane diagragm developed to identify activities required by functional engineering, resourcing for RTS activities as per the swim lane diagragm will be compared to projected resource profiles. Given the likelihood of resource issue the probability score has increased thus increasing the risk score to 9. Owner changed from D. Somerville to G. Leach by A. Kalafatis 2015/04/30 to align with AR assignment Initiator changed to M. Stewart, review in progress and staffing plans being developed.
			7539	In Progress	Produce a L3 RTS plan	Produce a L3 schedule of RTS activities in the schedule and ensure resource requirements are tallied for operations, maintenance, chemistry, environment, radiation protection, engineering and our vendor support. This will be used to compare to our current levels of staffing during these evolutions. Any gaps will be addressed by increasing staffing levels to the required numbers through staff movements to shift, additional staff from the station and the fleet or movement of the evolutions on the schedule if applicable. These options will be reviewed and concurred to by O&M, Eng and Work Control.	Gary Leach	Aris Kalafatis	14-Jul-17	Update Sept 14/2016: S2B/3/4 assessing milestone has been moved to June of 2017. A level 3 schedule will follow this milestone. Due date moved to a month after assessing to allow quality review and analysis of resources required. Review of the approved schedule to start following REV C issuance on June 17.
			7540	Not Started	Explore the need for EFIN/FIN during RTS	During RTS the critical path is affected by break plan discovery work that is not on the schedule. The work control process is not adequate to resolve these issues and maintain schedule integrity. Use of a FIN (fix it now) and EFIN (engineering) teams needs to be explored to see if staffing and funding can be achieved.	Gary Leach		30-Sep-17	June 15/16 - meetings with engineering and maintenance to be set up following Rev C issuance to discuss the possible use of these teams. Jan 5, 2017 - date extended to after assessing complete for RTS.
			7543	In Progress	Related to RTS prerequisites - ensure that PM's are planned & completed on critical instrumentation, NV's, etc, prior to start-up	FIAW/FOAK review board requested a review of RTS planning to ensure that required PM's on critical equipment are scheduled to ensure they do not delay start up activities. As an example, does the GCR RTS have the required activities planned to ensure it is available prior to being required.	Gary Leach	Aris Kalafatis	12-Jun-17	As part of the RTS logic reviews being completed these actions are being checked. Final reviews are to be completed by June 12/2017 to allow assessing. Date changed to reflect this date.

Outage Window	**Window Description**
000	000 – No Window Related
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.	093	093 - Low Power Testing & Heat-up
			094	094 - Power Escalation
			095	095 - Run-up & Sync
			096	096 - High Power Testing & Turbine Testing
			193	193 - Heat-up & Hot Condition

Program: Operations and Maintenance - 73440

775	Potential Shortfall for Commissioning Support	Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.		Active	Boris Vulanovic	Gary Leach	28-Feb-17	Mitigate	31-Jul-17	3	1	4	12	2	1	2	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			1308	In Progress	Commissioning Engineer resource profile	Review commissioning engineer resource profile and mitigate through contract staff hires if required. AR#28148291-01 Review commissioning engineer resource profile TCD:2017/01/15	Gary Leach	Steve Goodchild	14-Apr-17	12-JAN-2017 *** Update provided by Steve Goodchild **** Current strategy has been to develop the Engineering RTS Section with 6 staff of which 4 have arrived. The intent being that the system responsible staff in other sections will provide the support required for the commissioning activities. This strategy, based on previous OPEX may be challenged as the RTS group will be in more of a coordination role. The action is extended to allow for the current strategy to be further developed. _____ Update Sept 14/2016: Added Steve Goodchild as delegate to support with engineering resources. An engineering team to support commissioning and return to service has been formed. This group will support planning and execution of refurbishment and projects and modification work. ********** ********** ********** ********** ********** swim lane diagragm developed to identify activities required by functional engineering, resourcing for RTS activities as per the swim lane diagragm will be compared to projected resource profiles. Given the likelihood of resource issue the probability score has increased thus increasing the risk score to 9. Owner changed from D. Somerville to G. Leach by A. Kalafatis 2015/04/30 to align with AR assignment Initiator changed to M. Stewart, review in progress and staffing plans being developed.							
			7539	In Progress	Produce a L3 RTS plan	Produce a L3 schedule of RTS activities in the schedule and ensure resource requirements are tallied for operations, maintenance, chemistry, environment, radiation protection, engineering and our vendor support. This will be used to compare to our current levels of staffing during these evolutions. Any gaps will be addressed by increasing staffing levels to the required numbers through staff movements to shift, additional staff from the station and the fleet or movement of the evolutions on the schedule if applicable. These options will be reviewed and concurred to by O&M, Eng and Work Control.	Gary Leach	Aris Kalafatis	14-Jul-17	Update Sept 14/2016: S2B/3/4 assessing milestone has been moved to June of 2017. A level 3 schedule will follow this milestone. Due date moved to a month after assessing to allow quality review and analysis of resources required. Review of the approved schedule to start following REV C issuance on June 17.							

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

775

Potential Shortfall for Commissioning Support

Event: There is a risk that resource requirements for the return to service and commissioning phase of the project could exceed the NR O&M support capabilities Cause: The O&M program has established support organizations based on estimated resources for the various bundles including RTS and commissioning. Impact:This would require the station DN O&M to mobilize to assist in preserving the RTS schedule.

7540	Not Started	Explore the need for EFIN/FIN during RTS	During RTS the critical path is affected by break plan discovery work that is not on the schedule. The work control process is not adequate to resolve these issues and maintain schedule integrity. Use of a FIN (fix it now) and EFIN (engineering) teams needs to be explored to see if staffing and funding can be achieved.	Gary Leach		30-Sep-17	June 15/16 - meetings with engineering and maintenance to be set up following Rev C issuance to discuss the possible use of these teams. Jan 5, 2017 - date extended to after assessing complete for RTS.
7543	In Progress	Related to RTS prerequisites - ensure that PM's are planned & completed on critical instrumentation, NV's, etc, prior to start-up	FIAW/FOAK review board requested a review of RTS planning to ensure that required PM's on critical equipment are scheduled to ensure they do not delay start up activities. As an example, does the GCR RTS have the required activities planned to ensure it is available prior to being required.	Gary Leach	Aris Kalafatis	12-Jun-17	As part of the RTS logic reviews being completed these actions are being checked. Final reviews are to be completed by June 12/2017 to allow assessing. Date changed to reflect this date.

Outage Window	Window Description
000	000 – No Window Related
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC
093	093 - Low Power Testing & Heat-up
094	094 - Power Escalation
095	095 - Run-up & Sync
096	096 - High Power Testing & Turbine Testing
193	193 - Heat-up & Hot Condition

893

Additional Filter and IX Resin Waste following U2 PHTS Hot Conditioning

EVENT: Following U2 PHTS Hot Conditioning additional particulate material may be removed from the system through the purification system by means of filters and IX resin. CAUSE: Particulate material in the system resulting from overall Refurbishment and/or Hot Conditioning prior to RTS. IMPACT: Increase the frequency of filter and IX resin slurries, which would increase the amount of waste generated.

2	Active	Roger Daly	Sergei Voitchenko	28-Feb-17	Monitor	06-Sep-19	2	2	1	4	2	2	1	4

Outage Window	Window Description
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC
093	093 - Low Power Testing & Heat-up
094	094 - Power Escalation
095	095 - Run-up & Sync
193	193 - Heat-up & Hot Condition

There are no Draft, Not Started, In Progress Actions associated with the risk.

892

Additional Filter and IX Resin Waste following U2 PHTS Hot Conditioning

EVENT: Following U2 PHTS Hot Conditioning additional particulate material may be removed from the system through the purification system by means of filters and IX resin. CAUSE: Particulate material in the system resulting from overall Refurbishment and/or Hot Conditioning prior to RTS. IMPACT: Increase the frequency of filter and IX resin slurries, which would increase the amount of waste generated.

2	Active	Roger Daly	Sergei Voitchenko	28-Feb-17	Monitor	06-Sep-19	2	2	1	4	2	2	1	4

Outage Window	Window Description
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC
093	093 - Low Power Testing & Heat-up
094	094 - Power Escalation
095	095 - Run-up & Sync
193	193 - Heat-up & Hot Condition

There are no Draft, Not Started, In Progress Actions associated with the risk.

892

Additional Filter and IX Resin Waste following U2 PHTS Hot Conditioning

EVENT: Following U2 PHTS Hot Conditioning additional particulate material may be removed from the system through the purification system by means of filters and IX resin. CAUSE: Particulate material in the system resulting from overall Refurbishment and/or Hot Conditioning prior to RTS. IMPACT: Increase the frequency of filter and IX resin slurries, which would increase the amount of waste generated.

2	Active	Roger Daly	Sergei Voitchenko	28-Feb-17	Monitor	06-Sep-19	2	2	1	4	2	2	1	4

Outage Window	Window Description
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
092	092 - ATC
093	093 - Low Power Testing & Heat-up
094	094 - Power Escalation
095	095 - Run-up & Sync

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

893	Additional Filter and IX Resin Waste following U2 PHTS Hot Conditioning	EVENT: Following U2 PHTS Hot Conditioning additional particulate material may be removed from the system through the purification system by means of filters and IX resin. CAUSE:	193	193 - Heat-up & Hot Condition															
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
917	Ability to transfer and process downgraded D2O may impact Refur Schedule	Event: Many of the critical path items and several of the off critical path items could be negatively affected by our reduced ability to process and store downgraded D2O. Additionally there will be conflicts with U1 planned outage D1711 due to the same issue. Cause: TRF / D2O storage Capacity and Upgrader capability concerns Impact: Potential schedule impacts due to inability to process or store downgraded D2O in a timely fashion	4	Active	Boris Vulanovic	Yaro Sirota	27-Jan-17	Mitigate	31-Jan-17	2	1	1	2	1	1	1	1
			Outage Window		**Window Description**														
			134	134 - U1 Outage 2017 (D1711)															
			520	520 - D2O Storage Facility -PreReq to PHT Bulk Drain (Campus Plan)															
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
917	Ability to transfer and process downgraded D2O may impact Refur Schedule	Event: Many of the critical path items and several of the off critical path items could be negatively affected by our reduced ability to process and store downgraded D2O. Additionally there will be conflicts with U1 planned outage D1711 due to the same issue. Cause: TRF / D2O storage Capacity and Upgrader capability concerns Impact: Potential schedule impacts due to inability to process or store downgraded D2O in a timely fashion	4	Active	Boris Vulanovic	Yaro Sirota	27-Jan-17	Mitigate	31-Jan-17	2	1	1	2	1	1	1	1
			Outage Window		**Window Description**														
			134	134 - U1 Outage 2017 (D1711)															
			520	520 - D2O Storage Facility -PreReq to PHT Bulk Drain (Campus Plan)															
			There are no Draft, Not Started, In Progress Actions associated with the risk.																

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
751	Foreign Exchange Rate Changes Impact NR Cost Envelope	EVENT: Risk that fluctuations in foreign exchange rates adversely impact planned costs established at RQE, resulting in cost increases to the program. CAUSE: Ongoing and adverse fluctuations in USD/CAN exchange rate which impacts major contracts IMPACT: As of Jan-17, the current going forward USD/CAN exposure is estimated at $381M CAD. The foreign exchange risk is monitored in the Major Contract Summary section of the monthly Controllership report that is distributed to the CFO and NPET members. Over the past six months the exchange rate has had minor fluctuations of ~$0.05 (currently $1.34) and is relatively aligned to the RQE analysis rate of $1.34 (more favorable).		Active	Gary Rose	Derek Kindlon	24-Feb-17	Monitor	06-Jun-26	3	3	1	9	3	3	1	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
768	Program Interest Rate Uncertainty	RQE Program Basis (Assumption) for Interest Rates are documented in Assumption #536. This risk is to address uncertainty to this Basis for the entire NR Program. 2016 LT interest rates monitored by Corp Finance - assumptions reviewed for U2EE. Event: Controllership working with P&C group in Oct-16 to generate bundle interest calculation re-flow for business planning purposes. Cause: Changes to project costs and in-service timing which results in changes to interest. Impact: Determining the bundle and contingency interest flows; CCF processed at beginning of Nov (2521, 2543 to 2554)	1	Active	Gary Rose	Derek Kindlon	21-Feb-17	Accept	06-Jun-26	2	3	1	6	2	3	1	6
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
674	Loss of public and community support for Refurbishment	EVENT: A loss of public and community support for Darlington Refurbishment CAUSE: The reasons support may diminish include: There is a perception that nuclear base load is not needed in Ontario or alternatives are identified (e.g. Hydro Power from Quebec);The benefits of refurbishment are not seen/realized by the hosting communities (i.e. risks outweigh benefits); Nuclear waste stores at site increase, resulting in local opposition; New environmental issues surface at site; Performance of other OPG plants impacts ability to license; A major adverse nuclear event (at any nuclear power plant) results in negative public perception; or KI pill distribution in 2015 causes undue stress and anxiety. IMPACT: Darlington Refurbishment Project delay or postponement.	3	Active	Gary Rose	Scott Berry	22-Feb-17	Monitor	04-Dec-17	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
672	Public concern re: emergency preparedness or waste management plans delays Project	EVENT: The risk is that current public concerns regarding emergency preparedness/response plans could impact Refurbishment Project. CAUSE: The failure to move forward with waste management plans (e.g. DGR, or NWMO used fuel repository) for refurbishment and continued operations. IMPACT: This could delay Refurbishment execution.	3	Active	Gary Rose	Scott Berry	22-Feb-17	Monitor	04-Dec-17	1	1	1	1	1	1	1	1
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
683	Poor EPC Vendor performance has required additional oversight during all phases, resulting in an increase in staff costs in OPG	Event: Poor Vendor Performance creates the requirement for increased Vendor Oversight. Cause: Based on the experience of the past three CANDU refurbishments and the Prerequisite work on DRNU2 the Owner has had to become significantly involved in all phases (Definition through Execution) due to the Vendor's inability to meet contractual commitments on cost, schedule and quality. This has required the Owner to build an oversight organization capable of supporting/directing the planning, execution and technical supervision of the work. Impact: Current RQE forecast of OPG oversight manpower/cost assumes the EPC contractors for DNR will have the required capabilities to meet the contractual commitments on safety, quality, cost and schedule. Should the OPEX repeat itself on DNR then significant schedule impact could occur and considerable qualified oversight resources would be required.	3	Active	Ken Hobbs	Peter Robson	21-Feb-17	Mitigate	15-Aug-19	4	3	4	16	1	2	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1457	In Progress	Risk Action 683	Scale the Construction Oversight Group with the required quantity of specialists (Engineering/Procurement, Facilitators/coordinators, welding, NDE, Quality and safety) outside of the project teams to ensure both objectivity of oversight and provide the needed support/guidance to the vendros. These refurbishment experienced specialists and support staff may not reside within OPG. This strategy will be more cost effective and scalable than building up the individual project teams.	Ken Hobbs	Peter Robson	15-Aug-19	Construction Oversight Group has been established with resource level and organizational make up approved. Required specialists, FME, Hoisting and Rigging, Pressure Boundary, Electrical, etc. Specific Construction Oversight qualification has been developed and implemented. Current organization will be tested through the 5 RTE Projects schedule for 2016 prior to breaker open. Lessons Learned will be incorperated prior to U2 breaker open. Lessons learned and self assessments are now in progress on some of the RTE test Projects. Follow up a/r's to be identified. The Construction Organization is adding additional resources to ensure the correct level of oversight can be applied. Current staffing of Construction Oversight is 70% complete to Maximum level.

Outage Window	Window Description
000	000 – No Window Related

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
762	Key skilled craft resources not available when required for Units 3, 1, 4 Execution	Event: Resources unavailable in the Union Halls Cause: Bruce Power Refurbishment or other large mega Projects are started in Canada, the price of Oil Increases Impact: Schedule and Cost Impact to the Refurbishment Project. Refurbishment Project Contractors will be unable to secure the number of required key skilled craft resources for Units 3, 1 and 4 Execution like boilermakers, pipefitters, welders, millwrights and electricians as a result of attrition in the trades and other mega-project opportunities which may lead to schedule delays and cost overruns.	1	Active	Ken Hobbs	Andy Forsyth	21-Feb-17	Mitigate	16-Oct-26	4	3	4	16	3	3	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1449	In Progress	Risk Action (Re Risk 0002 & 762)	Part One: Evaluation of tactics and development of an Action Plan aligned with owners strategy to minimize the risk of skilled craft shortages. The tactics evaluated will inlude both short term approaches (i.e. temporary foreign workers) and longer term solutions (i.e. outreach to schools, apprentices, targeting underrepresented groups). Part Two: Work with BuildForce Canada and other owners on strategies to address construction and maintenance workforce challenges.	Ken Hobbs	Andy Forsyth	15-Aug-19	• Ongoing assessments, of resources, planned right up to breaker open on first unit. •Overall action plan NK38-PLAN-09701-10231 issued in Asset Suite on Nov 20th,2014 • Build force refresh in 2016 • Increase apprentice number of Aug staff by min. 20% NK38-PLAN-09701-10231 to be refreshed. EPSCA Buildforce analysis will support this initiative. Update 2016-07-13. Buildforce have provided a cost estimate to EPSCA for the 2016 Analysis as of this date. EPSCA review in Progress. Robin Granger, Aug 5th. Followed up with EPSCA and they are still reviewing Estimate.

762	Key skilled craft resources not available when required for Units 3, 1, 4 Execution	Event: Resources unavailable in the Union Halls Cause: Bruce Power Refurbishment or other large mega Projects are started in Canada, the price of Oil Increases Impact: Schedule and Cost Impact to the Refurbishment Project. Refurbishment Project Contractors will be unable to secure the number of required key skilled craft resources for Units 3, 1 and 4 Execution like boilermakers, pipefitters, welders, millwrights and electricians as a result of attrition in the trades and other mega-project opportunities which may lead to schedule delays and cost overruns.	6286	In Progress	Resouce Planning for Units 3, 1, 4.	Evaluation of tactics and aligned with owners strategy to minimize the risk of skilled craft shortages. The tactics evaluated will inlude both short term approaches (i.e. temporary foreign workers) and longer term solutions (i.e. outreach to schools, apprentices, targeting underrepresented groups). Process is similar to Action 1449 but for Units 3,1,4.	Ken Hobbs	Andy Forsyth	30-Jun-23	• Ongoing assessments of resources planned right up to breaker open on last unit, Unit 4. •Overall action plan NK38-PLAN-09701-10231 issued in Asset Suite on Nov 20th,2014 Robin Granger Aug 5th. Action 1449 Updated re EPSCA reviewing Buildforce Estimate as of August 5th.
			Outage Window		**Window Description**						
			000		000 – No Window Related						
814	EHS and other Vault Projects - Radiography Cannot be Completed on Schedule Due to Critical Path Work (windows 104)	EVENT: The risk is that non-destructive examination (NDE), in the form of radiography, cannot be completed on schedule to verify nuclear class piping welds due to potential critical path impacts. Radiography is a high rad hazard and requires evacuation of the vault which may not be feasible due to critical path work completed by the JV. This will lead to schedule impacts for the Emergency Heat Sink (EHS) project, valve rehabilitation, valve PM's, and other projects to find time to complete radiography NDE. CAUSE: Using traditional methods for radiography requires vault evacuation. IMPACT: The potential impact as a result of vault evacuation is a delay to critical path work; all staff to exit the vault. The current known scope of weld to be radiographed is approximately 185 welds in the vault. Per SCR N-2016-02304 it was raised that radiography may not be allowed to be performed in the vault, to prevent impacts to critical path work being performed by the JV. Per June 21/16 CCB meeting - implementation of PAUT for non-BoP projects (such as LRVs, STOP, D2O sample lines) may require contingency funding from program contingency. Funding for BoP related PAUT will first come from BoP bundle contingency before any program funding request is made (if required).	3	Active	Michael Allen	Kristopher Probodiak	01-Mar-17	Mitigate	31-May-17	5	1	3	15	3	1	2	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**						

814	EHS and other Vault Projects - Radiography Cannot be Completed on Schedule Due to Critical Path Work (windows 104)	EVENT: The risk is that non-destructive examination (NDE), in the form of radiography, cannot be completed on schedule to verify nuclear class piping welds due to potential critical path impacts. Radiography is a high rad hazard and requires evacuation of the vault which may not be feasible due to critical path work completed by the JV. This will lead to schedule impacts for the Emergency Heat Sink (EHS) project, valve rehabilitation, valve PM's, and other projects to find time to complete radiography NDE. CAUSE: Using traditional methods for radiography requires vault evacuation. IMPACT: The potential impact as a result of vault evacuation is a delay to critical path work; all staff to exit the vault. The current known scope of weld to be radiographed is approximately 185 welds in the vault. Per SCR N-2016-02304 it was raised that radiography may not be allowed to be performed in the vault, to prevent impacts to critical path work being performed by the JV. Per June 21/16 CCB meeting - implementation of PAUT for non-BoP projects (such as LRVs, STOP, D2O sample lines) may require contingency funding from program contingency. Funding for BoP related PAUT will first come from BoP bundle contingency before any program funding request is made (if required).	**3436**	In Progress	Alternate NDE Required: Radiography Cannot be Performed inside the Vault	Currently identified ~82 piping welds inside the vault (excluding feeders). the balance of plant and P&M scope is listed below. The action is to develop a path forward for an alternative to conventional radiography and implement these alternatives. Note: Action due date is tied to completion of first occurrence of alternate RT methods. Project # Project Name Applicable Window Start of Welding NDE Locations 73202 NR TS0100-2: ECT INSPECT BLEED COOLER 2-33320-HX2 (Cont'g ONLY) 105 Sept 2017 2 73648 NR DSR SI0050-1 EMERGENCY HEAT SINK MECH 2-33410-L124 105 May 2017 22 73380 DR SIO Shield Tank Over Press Protection (STOP) 105 1-Aug-18 5 73763 REPLACE 2-33330-PV1 VALVE BODY 105 7-Sep-17 2 38349 Spectacle Flange Replacements TBD August, 2017 10 38933 DN PHT LRV Modifications (Waterhammer) 31 June, 2017 35 73407 Check Valve Replacements (NV23, 24, 61, 36) 105	Scott Guthrie	Kristopher Probodiak	31-May-17	March 1, 2017 Small Controlled Area Radiography and Pulsed X-Ray are currently available options and alternatives to conventional radiography. Actions are in place to enable projects. Safety, Quality, Schedule, etc. are being addressed and reported on regularly at the project issues meeting. Funding has been made available to have IMS support the initiative and provide QA oversight, RP planning, etc. Refer to issue 294 for regular updates. first occurrence of SCAR is expected in May 2017 pending any project schedule changes. ***OLD Status Updates prior to Feb 2017***** all work groups/ projects to id their vault radiography requirements to Dennis. Boyd - requested to determine other if other "non-radiography" technologies avail. Jan 15th, 2015: Did discuss this with vendors (ES Fox and AMEC) and we have a path forward to determine radiography amounts (still unknown as piping modelling is underway), I'll get you detailed drawings when the modelling is done. 4Feb2015 note: all in vault projects to strive to not have to radiograph. As JV is working 6x10h: Sunday will be "radiography day". 28Apr2015 note: unkown currently how much radiography is required...this will be known better as design progresses. Due date pushed to EHS 40% design complete date for follow up. Vendor looking into other forms of NDE for pipe welds. 4-Sept-2015 Update: Will confirm amount of NDE through assessing/work planning phase. 3-Feb-2016: it was recently raised in the vault window meeting that radiography may not be allowed. This will affect multiple projects in the vault project window that require radiography. Other means of NDE is being investigated. 5-Apr-2016: This action is going to be canceled once a new action is generated and linked to a Program Risk, instead of Project Risk. The new action will be noted before this action is closed. Updates: Contacted IMS to investigate Phased Array option as an alternative. IMS to deliver proposal to BOP. 22 June 2016 (J.Stopar): This Proj

						20-Feb-18 4 73750 Valve PMs - 2-32110-NV37 TBD 17-Jul-18 2															
			Outage Window		**Window Description**																
			104		104 - Post Feeder Vault Projects																
			105		105 - Vault Projects After Feeder Removal																
887	Vendor CWP's are late and/or of poor quality impacting field execution with delays, cost over	Event: Vendor CWPs are late and/or poor quality. Cause: Late and/or of poor quality completion of detailed engineering, lack of qualified resources to prepare and review CWP's, lack of a defined detailed managed CWP process and not adhering to the managed CWP process. Impact: CWP revisions/rework will be required, Poor quality CWP leads to potential delays during execution, impact quality of maintenance.	1	Active	Ken Hobbs	Tom Lance	22-Feb-17	Mitigate	15-Aug-19	4	3	3	12	1	1	2	2				
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**											
			1699	In Progress	Risk Action	The following mitigation actions must be implemented on each scope bundle by each of the OPG PM's:Ensure the vendor detailed design completion milestones are established taking into account the duration of preparing the CWP's while adhering to the CWP managed process.Ensure the vendors have a defined and detailed CWP managed process.Ensure the vendor adheres to the approved CWP managed process through strategic and routine OS.Ensure the vendor has both quantity and quality of resources to prepare and review the CWP'sEnsure the vendor CWP managed process incorporates field walkdowns of the work area and equipment and that this process is followed.Ensure the vendor involves BTU field supervision in the preparation and review of CWP's.	Ken Hobbs	Tom Lance	15-Aug-19	All Vendors have established CWP Program in place, OPG has issued a CWP Guideline to help Vendors develop programs. All Vendor CWPs require review and acceptance of OPG through Operational and Technical reviews as the initial look for quality of packages. Even though the assessments are late and being done in two phases with the final phase due in Sept. 2016 the quality checks are still covered through the use of the Look Ahead Teams to review CWPs/Work Instructions through , Construction Readiness Reviews and Execution Phase Challenge/Walk down. Risk action also in place to document process for CWP tear out to define what is required to be in field to support execution.										
			Outage Window		**Window Description**																
			000		000 – No Window Related																
781	TG-Turbine Generator issues during dynamic testing	EVENT:There is a chance that during the dynamic commissioning of the Turbine Generator we might encounter various issues. The timeline of the dynamic commissioning of the T/G project can also be impacted due to the plant condition, emergent issues. CAUSE: This issues might include but are not limited to various equipment performance issues such as equipment failure and maintenance related failures & software related issues such as software logic malfunctions, dynamic logic and parameter tune up issues. For this event only risks that have the most probability of occurring are considered and does not take under consideration any catastrophic scenarios. Also to complete the dynamic commissioning the plant condition will require steam and all other systems to be in clear status. If a system is unavailable or the plant condition due not allow steam it will impact the timeline of dynamic commissioning IMPACT: This will impact the critical path of the schedule and cost.	1	Active	Michael Allen	Todd Josifovski	23-Feb-17	Mitigate	01-Feb-19	3	2	4	12	2	2	3	6				
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**											
			2225	In Progress	TG Movement of Project Onto Critical Path	1) Incorporating lessons learned from the past and involvement of OEM in development of the commissioning specs.	Todd Josifovski	Peter Moore	01-Jan-18												
			3020	In Progress	Evaluate need for third party review of commissioning specs	Third party review of the commissioning plans prior to the phase; related to Risk #11208.	Peter Moore	Swaroop Puwar	01-May-17	TCD pushed to June 30 to reflect strategy for JV engineering timing/strategy. TCD pushed as per latest update (A Puci June 30, 2016)											
			3021	In Progress	Use of static comissioning to minimize the dynamic commision	Where feasible, static commissioning will be used to minimize the dynamic commission requirements, to the extent possible.	Peter Moore	Arber Puci	15-Dec-18												
			8104	Not Started	TG Perform control FAT testing	The Turbine Generator will conduct Factory Acceptance tests for the new Turbine and Generator digital controls. Factory Acceptance Test to be completed on vendor site and witnessed by OPG.	Peter Moore		28-Apr-17												
			8105	Not Started	TG Full Scope Maintenance simulator	The TG project as part of the scope will be procuring a Full Scope Maintenance simulator. This Full Scope Maintenance simulator will be installed in the MCDF and provide a chance to test the control equipment and fine tune them prior to the dynamic commissioning. This action is to complete the installation of the Full Scope Maintenance simulator	Peter Moore	Soorena Merat	07-Sep-17												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

781	TG-Turbine Generator issues during dynamic testing	EVENT:There is a chance that during the dynamic commissioning of the Turbine Generator we might encounter various issues. The timeline of the dynamic commissioning of the T/G project can also be impacted due to the plant condition, emergent issues. CAUSE: This issues might include but are not limited to various equipment performance issues such as	8106	In Progress	TG Review PFUP logic	Review the logic and comparing the current logic with the new logic proposed. Accept the vendors proposed PFUP logic and issue the documentation.	Peter Moore	Swaroop Puwar	01-Nov-17										
			Outage Window		**Window Description**														
			095		095 - Run-up & Sync														
784	Refurbishment does not retain key trades and supporting staff	Event: The risk is that refurbishment does not retain key trades and supporting staff through the low demands period between U2 and U3. Cause: Staff go onto other Projects if not able to retain key staff. Impact: will have high impact on re-hiring qualified staff when needed for U3, both Schedule and Costs.	2	Active	Ken Hobbs	William Owens	23-Feb-17	Mitigate	15-Oct-19	3	3	4	12	2	3	3	6	
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									
			5772	In Progress	Develop contingency plan	Develop contingency plan with several option to mitigate this risk. 1. Review over lapping strategy between U2 and U3 2. Schedule trades into U2/U3 trough 3. Resources sharing with vendor capability 4. Resources sharing with OPG/ Bruce refurbishment programs 5. Training development opportunities 6. New projects that could mitigate risk i.e. marginal mega-watt project	William Owens		15-Aug-17	The next step for this action is to meet with the associated unions and discuss the need to retain critical trades through the trough period and to look ahead at the project portfolio for Darlington and Pickering to identify opportunities for trade relocation. A person will be brought into the execution organisation to assist with developing the contingency plan.								
			Outage Window		**Window Description**														
			000		000 – No Window Related														
855	Office Space Requirements OPG/Vendor in Support of Refurbishment	Event: Insufficient office space requirements to support OPG/Vendor requirements for Refurbishment. Cause: Influx of staff for OPG and Vendor as we approach breaker open. Impact: Increased costs over estimated to support purchase/rental and maintenance of trailers and/or additional office space.	3	Active	Ken Hobbs	Al Acorn	22-Feb-17	Mitigate	30-Jun-17	3	3	1	9	2	2	1	4	
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									
			7995	In Progress	Risk 855-Insufficient Office Space to Support OPG/Vendor Requirements for Refurbishment	Insufficient Office Requirements to Support OPG/Vendor requirements. Develop a Plan for Darlington Refurbishment and Projects Accommodations.	Ken Hobbs	Al Acorn	30-Jun-17	Draft Terms of Reference has been developed. Level 1 Development in progress to be presented to Darlington Station VP July 8, 2016.									
			Outage Window		**Window Description**														
			000		000 – No Window Related														
881	Added Shift Coverage and/or Overtime Impacting Construction Oversight Availability and Cost	Event: Added Shift Coverage and/or Overtime required to Support Vendor Field Oversight. Cause: Project schedule slippage is causing the Projects to add shifts and use of overtime to recover schedule. Impact: Added Shift Coverage has potential impact to availability to support other oversight activities. Increased use of overtime has impact to cost and also will impact availability of Society Staff for Overtime worked per quarter/per year.	3	Active	Ken Hobbs	Andy Forsyth	22-Feb-17	Mitigate	15-Aug-19	3	3	1	9	2	3	1	6	
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									
			7905	In Progress	Risk 881-Added Shift Coverage and/or Overtime Impacting Construction Oversight Availability and Cost	Added Shift Coverage and/or Overtime Potentially Impacting Construction Execution Availability and Cost.	Ken Hobbs	Andy Forsyth	15-Aug-19	Monitor Overtime usage per person to determine impact to availability due to hours worked. Added Shift Coverage and/or Overtime will have impact to budget for both Society and augmented staff.									
			Outage Window		**Window Description**														
			000		000 – No Window Related														
550	Significant contractor event occurs	Event: The risk is that project related High Maximum Reasonable Potential for Harm (High-MRPH) events. Cause: Poor execution of work practices. Impact: Negative effect on the project schedule and result in financial loss..	1	Active	Ken Hobbs	Tom Lance	23-Feb-17	Mitigate	15-Aug-19	2	1	3	6	1	1	2	2	
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**									
			1290	In Progress	Risk 550-High MRPH Event Impact	High MRPH Event causes schedule and financial impact.	Ken Hobbs	Tom Lance	15-Aug-19	Risk Response Strategy-Mitigate: Construction Execution Oversight to ensure safety and quality of Construction by monitoring behaviors and coaching Vendor Supervision in proper practices. Oversight Plans identify critical activities and oversight requirements for high risk activities and supporting by Risk Matrix to mitigate the risks. Vendor Supervisors are having additional training to understand what good looks like for Leadership Training, Pre Job Planning, bolted joint as examples.									
			Outage Window		**Window Description**														
			000		000 – No Window Related														

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

783	Estimated Cost of General Services contract may be underestimated	Event: The risk is that Estimated Cost of General Services contract may be underestimated, the current estimate is based on third party estimate but vendor bids could be higher. Cause: If bids for General Services Contract exceeds the estimate which was based on third party estimate. Impact: Financial impact as budgeted amount based on estimate.	4	Active	Ken Hobbs	Al Acorn	22-Feb-17	Monitor	31-Oct-17	2	3	1	6	2	3	1	6

Outage Window	Window Description
000	000 – No Window Related

There are no Not Started, In Progress Actions associated with the risk.

888	Significant Hoisting and Rigging Event	Event: Significant Hoisting and Rigging Event. (Recent industry OPEX, such as the fatality at Arkansas One NGS, identifies a need to apply extensive rigor and detail in the critical lift program.) Cause: Improper Hoisting and Rigging techniques causes rigging failure. Impact: Rigging failure could result in personnel injury, death, or sever damage to plant structure and/or equipment. Impact Schedule and Cost.	3	Active	Ken Hobbs	Pieter Den Decker	23-Feb-17	Mitigate	15-Aug-19	1	5	5	5	1	5	5	5

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
8461	In Progress	Risk 888-Significant Hoisting and Rigging Event	Mitigation Plan: 1. All Critical Lift Plans are reviewed by Vendors Engineering and Safety and subsequently accepted by OPG Civil Engineering and Conventional Safety. The Hoisting and Rigging SME will do a final review and approval for use to ensure proper rigor built into lift plans. 2. Complex Lift Plans require Engineering Review will be reviewed by Vendors Engineering and subsequently accepted by OPG Civil Engineering. 3. Rigging from plant structures other then designated lift points or cranes will be reviewed and approved by OPG Civil Engineering. 4. Hoisting and Rigging SME will provide continues support to Vendors during development of lift plans and will assist when field circumstances require changes. 5. Construction Execution Hoisting and Rigging SME provided Desk Top exercise/training with Vendors on Lift Plan requirements. 6. Safe Work Plans reviewed by Safety Department. 7. Vendor Supervisory Training Module development in progress for Safe Work Planning. 8. Hoisting and Rigging requirements are reviewed by Look Ahead Team at T-6 to T-3 Months and T-4 Week Execution Walk down. 9. Critical lifts are identified as a critical activity during execution and is built into Construction Execution Oversight Plan for Vendors and Risk Matrix with mitigating actions. 10. Hoisting and Rigging SME has field presence during lifts.	Ken Hobbs	Pieter Den Decker	15-Aug-19	1. All Critical Lift Plans are reviewed by Vendors Engineering and Safety and subsequently accepted by OPG Civil Engineering and Conventional Safety. The Hoisting and Rigging SME will do a final review and approval for use to ensure proper rigor built into lift plans. 2. Complex Lift Plans require Engineering Review will be reviewed by Vendors Engineering and subsequently accepted by OPG Civil Engineering. 3. Rigging from plant structures other then designated lift points or cranes will be reviewed and approved by OPG Civil Engineering. 4. Hoisting and Rigging SME will provide continues support to Vendors during development of lift plans and will assist when field circumstances require changes. 5. Construction Execution Hoisting and Rigging SME provided Desk Top exercise/training with Vendors on Lift Plan requirements. 6. Safe Work Plans reviewed by Safety Department. 7. Vendor Supervisory Training Module development in progress for Safe Work Planning. 8. Hoisting and Rigging requirements are reviewed by Look Ahead Team at T-6 to T-3 Months and T-4 Week Execution Walk down. 9. Critical lifts are identified as a critical activity during execution and is built into Construction Execution Oversight Plan for Vendors and Risk Matrix with mitigating actions. 10. Hoisting and Rigging SME has field presence during lifts.

Outage Window	Window Description
000	000 – No Window Related

685	U2 Containment Isolation schedule extension due to Fuel Handling operations on operating units. [window 23]	Event: The critical path isolation of the NR unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. Cause: Critical path containment isolation activities can only be completed during no-fueling windows. The frequency/availability and duration of no-fueling windows is determined by operating unit zone levels, trolley reliability and required trolley maintenance. Impact: If no fueling windows are shortened or do not occur per plan, critical path schedule delays will result as well as cost overruns due to crew standby time. Reasons for no fueling windows not occurring as planned could include unit zone conditions and trolley reliability.	2	Active	Michael Allen	Bert Boston	30-Nov-16	Monitor	31-Oct-16	1	1	4	4	1	1	4	4

Outage Window	Window Description
000	000 – No Window Related
014	014 - Containment Mod Commissioning
017	017 - Install ATP and End Fitting Caps - FM Carriage
023	023 - Install Bulkheads
024	024 - Containment Pre Test, Achieve Dew Point & Containment Test
025	025 - Install Bulkhead Shielding

685 — U2 Containment Isolation schedule extension due to Fuel Handling operations on operating units.

Event: The critical path isolation of the NR unit from containment (bulkhead installation), and subsequent removal post fuel channel and feeder replacement, may extend beyond scheduled windows. Cause: Critical path containment isolation

Outage Window	Window Description
085	085 - AL Closed, Shielding Removal & Pressure Test
088	088 - Bulkhead Removal

There are no Not Started, In Progress Actions associated with the risk.

782 — Vendor Default

EVENT: a major NR vendor becomes unwilling or unable to execute the work they have been contracted to perform CAUSE: may be many causes such as bankruptcy, labour issues, corporate change in direction, etc IMPACT: need to secure a new qualified vendor to perform the scope of work which will impact schedule and cost The risk is that a major NR vendor becomes unwilling or unable to execute the work they have been contracted to perform, resulting in a need to secure a new qualified vendor to perform the scope of work.

	Status											
	Active	Roy Martin	Carol Gregoris	14-Oct-16	Accept	31-Dec-19	1	4	1	4	1	4	1	4

Outage Window	Window Description
000	000 – No Window Related

There are no Not Started, In Progress Actions associated with the risk.

2 — Key skilled craft resources not available when required for Unit 2 Execution

Event: Refurbishment Project Contractors will be unable to secure the number of required key skilled craft resources for unit 2 Execution like boilermakers, pipefitters, welders, millwrights and electricians. Cause: As a result of attrition in the trades and other mega-project opportunities. Impact: Would lead to schedule delays and cost overruns.

	Status											
1	Active	Ken Hobbs	Andy Forsyth	21-Feb-17	Mitigate	15-Aug-19	1	1	2	2	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1449	In Progress	Risk Action (Re Risk 0002 & 762)	Part One: Evaluation of tactics and development of an Action Plan aligned with owners strategy to minimize the risk of skilled craft shortages. The tactics evaluated will inlude both short term approaches (i.e. temporary foreign workers) and longer term solutions (i.e. outreach to schools, apprentices, targeting underrepresented groups). Part Two: Work with BuildForce Canada and other owners on strategies to address construction and maintenance workforce challenges.	Ken Hobbs	Andy Forsyth	15-Aug-19	• Ongoing assessments, of resources, planned right up to breaker open on first unit. •Overall action plan NK38-PLAN-09701-10231 issued in Asset Suite on Nov 20th,2014 • Build force refresh in 2016 • Increase apprentice number of Aug staff by min. 20% NK38-PLAN-09701-10231 to be refreshed. EPSCA Buildforce analysis will support this initiative. Update 2016-07-13. Buildforce have provided a cost estimate to EPSCA for the 2016 Analysis as of this date. EPSCA review in Progress. Robin Granger, Aug 5th. Followed up with EPSCA and they are still reviewing Estimate.

Outage Window	Window Description
042	042 - Feeder Removal

684 — Primary Side Clean Adverse Impact to SG Tube Integrity

EVENT: SG tube thinning beyond allowable limits. CAUST: Primary Side Clean (magnetite removal process) could potentially remove tube wall material. IMPACT (from highest to lowest probability): 1. SG tube thinningcould result in the need for additional tube plugging which would extend the PSC execution window. 2. Depending on the amount of tube plugging needed, the station may need to de-rate the unit. 3. In the unlikely event that the tube damage is so severe that de-rating the unit is not ecomincally viable, complete SG replacement may be required.

	Status											
2	Active	Michael Allen	Pejman Asgaripour	21-Feb-17	Mitigate	01-Nov-18	1	2	2	2	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
1731	In Progress	Review PSC OPEX regarding Primary Side Clean Adverse Impact to SG Tube Integrity prior to execution window (T-6month)	Review PSC OPEX regarding Primary Side Clean Adverse Impact to SG Tube Integrity prior to execution window (T-6month)	Pejman Asgaripour	Mike Lutz	23-Aug-17	As pre req to this action, optimization will include extended duration tests to ensure visible wear is produced. Visible wear will clearly identify how process parameter adjustments affect tube wear, allowing verification of future decisions that may occur(ie increase execution blast duration). future operating pressures will be within the bounds of qualification completed in 2009. Review OPEX with EPC vendor following PSC campaign in Cernavoda in Q2 2016.

Outage Window	Window Description
062	062 - Primary Side SG Clean and Inspect

755 — Vendor Purchased or Owner Supplied Materials not arriving in time to support the NR Execution Schedule

EVENT: The risk is that vendor purchased or owner supplied materials not arriving in time to support the NR execution CAUSE: This may be due to lack of vendor capability or due to invisibility on the status and progress of procurements materials for each or of the bundles IMPACT: May lead to NR projects suffering schedule delay and increased cost.

	Status											
3	Active	Michael Allen	Sean Toohey	21-Feb-17	Monitor	31-Oct-16	1	1	2	2	1	1	2	2

Outage Window	Window Description
000	000 – No Window Related

There are no Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 08-Mar-17 10:30 PM

778	D2O Cost Overrun	Event: NR will not have sufficient storage space for D2O from HTS Drain and Dry, and Moderator Drain. Cause: D20 project schedule extends due to field execution issues, vendor on boarding issues, and discovery work Impact: NR has to make alternative arrangement to store Heavy Water while D2O Heavy Water storage facility unavailable, shipping containers/drums to Pickering site or even Bruce Power site.	4	Active	Michael Allen	Gary Rose	22-Feb-17	Monitor	31-Oct-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**															
			013		013 - PHT Bulk Drain (Includes V42 Mod)															
			There are no Not Started, In Progress Actions associated with the risk.																	
825	Fresh Fuel Start up Anomalies	The risk is that anomalies associated with fresh fuel are encountered on Unit 2 startup due to discovery issues around low power testing and power monitoring component resulting in cost increase/schedule delay or safety risk during start up evolution.	1	Active	Michael Allen	Gerry Martin	17-Feb-17	Monitor	14-Jan-19	2	2	2	4	1	1	2	2
			Outage Window		**Window Description**															
			133		133 - RTS Segment PMs & Miscellaneous Work															
			There are no Not Started, In Progress Actions associated with the risk.																	
Program: Refurbishment Execution - 73113																				
890	Feeder fabrication schedule delay as a result of flow element (I690) weldability challenges. [Window 076 , 083]	[Execution Phase] JV Risk ID: 8.135 Event: There is a risk of delays to feeder fabrication schedule. Cause: Flow Element and Pressure Breakdown Orifices material has been changed to Inconel 690 from Inconel 600 per DRAS 584. Challenges associated with dissimilar metal welding procedures development and qualification for Inconel 690 using filler metal 52M are expected. Impact: Potential delay to critical path due to late arrival of upper feeders.	2	Active	Michael Allen	Roy Brown	28-Feb-17	Mitigate	01-May-17	3	1	4	12	3	1	4	12
			Outage Window		**Window Description**															
			076		076 - Upper Feeder Installation															
			083		083 - Lower Feeder Installation															
			There are no Not Started, In Progress Actions associated with the risk.																	

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
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Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
Project: Specialized Projects - 73310																	
11982	Delay In Contracting Process Impacting SDS Project Schedule [Window 7]	Event: Delay in material availability. Cause: Delay in SDS procurement contract issuance results in a delay of material availability for installation. Impact: Cost and schedule of the project would be impacted if materials were unavailable on time.	4	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Mitigate	31-Dec-17	2	1	4	8	2	1	4	8

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2713	In Progress	Expedite new contract process	Hold regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts until all Project contracts have been issued.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts. As a result, a number of contracts have been issued. This level of oversight will continue as required. All the other contracts, including service and cables (regarding to 3220) We may still need to exercise and expedite hiring of resources for installation - 31-Jun-2017

Outage Window	Window Description
007	007 - SDS1 & SDS2 Mods & Rehab

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
12323	Hardware Delivery Delay Impacting SDS Software Integration [Work Window 7]	Event: Hardware delivery is late reducing the time available to integrate hardware components with avilable software. Cause: The late issuance of hardware contracts squeezes the equipment supplliers reducing their available float and their ability to handle unexpected changes. Impact: This risk would cause a significant schedule impact which would in turn impact cost.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	31-Dec-17	2	1	3	6	2	1	3	6

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
2713	In Progress	Expedite new contract process	Hold regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts until all Project contracts have been issued.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Regular periodic meetings are held with Supply Chain to review the status and expedite pending contracts. As a result, a number of contracts have been issued. This level of oversight will continue as required. All the other contracts, including service and cables (regarding to 3220) We may still need to exercise and expedite hiring of resources for installation - 31-Jun-2017

Outage Window	Window Description
007	007 - SDS1 & SDS2 Mods & Rehab

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
13463	SDS Interface Compatibility Issues Discovered During Installation [Window 7]	Event: SDS computer compatibility issues during installation. Cause: The system will be thoroughly tested prior to installation under simulated conditions but some conditions (Ispecifically driving actual field solenoid valves) cannot be simulated and therefore must be tested in the field. Impact: Both cost and schedule would be impacted by the interface compatibility issues if they arise.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Accept	30-Jun-18	2	1	3	6	1	1	3	3
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
12327	SDS Computer Project Failure to Meet Hardware Design Requirements [Window 7]	Event: The system as designed fails to meet design requirements during design testing and qualification. Cause: Latent design flaws. Impact: Both cost and schedule could be impacted due to substantial rework being required.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	31-Dec-17	1	1	4	4	1	1	4	4
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
14511	SDS Computer Qualified Resources Unavailable During Execution [Window 5,7,12]	EVENT: Delay due to a reassignment of SDS execution resources CAUSE: The resources currently assigned per the current SDS execution resourcing strategy are unavailable, requiring the contracting of resources less familiar with the site, system and scope of work and resulting in a delay to the schedule. IMPACT: Schedule is pushed resulting in a cost impact to the project because the work cannot be completed as planned.		Active	Ivan Dimitrov	Dale Schnedler	02-Mar-17	Mitigate	31-Dec-17	1	1	4	4	1	1	4	4
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7761	In Progress	SDS Computers Resourcing Follow Up	Follow up with Darlington Projects and Control Maintenance to ensure that SDS qualified resources are available to support installation of the replacement SDS Computers. Develop and document a resource strategy for execution.	Ivan Dimitrov	P Sharawy	30-Jul-17	Work in this area has progressed as follows. · Breakdown of BTU and PWU installation effort provided and approved in accordance with CPAA in October, 2016. · Follow up meeting with Darlington Projects and Control Maintenance (Refurbishment) to review scope, effort and resource requirements in October, 2016. · Follow up meeting with Control Maintenance Darlington to review scope, effort and resource needs in December, 2016. · There is still a risk that sufficient SDS qualified resources would not be available to support installation. Need to confirm availability closer to installation				
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
12328	SDS Computer Project Grounding Problem [Window 7]	Event: SDS Computer grounding discovered during install. Cause: Grounding has been an issue in past computer system installations therefore there is a risk tha the same issue will arise with the installation of the new equipment. Impact: Both cost and schedule ofthe project would be impacted.	1	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Monitor	30-Jun-18	1	1	3	3	1	1	3	3
			Outage Window		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
13464	SDS Equipment Fails During Installation [Window 7]	Event: SDS Equipment fails during or before installation. Cause: All SDS computer components are being prcured at the same time therefore, by the time the parts are installed for U4 refrubishmnet they will have been in storage for 7 years creating a risk that they will fail when installed. Impact: The failure of the equipment will have an impact on both cost and schedule as replacement components will have to be procured and installed.	2	Active	Sorin Marinescu	Dale Schnedler	02-Mar-17	Mitigate	30-Jun-18	1	1	3	3	1	1	3	3
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			5194	In Progress	Spare part purchases for vulnerable components	Confirm and order spares for vulnerable components.	Sorin Marinescu	P Sharawy	31-Dec-17	Update June 6, 2016 - Action date changed to correspond to the date currently scheduled for issuing the last production Purchase Order for the SDS Computers Replacement Project, including the operational spare parts for the SDS2 Trip Computers. This Purchase Order is scheduled after completion of the Hardware Qualification Tests of the system in order to ensure a complete list of spare parts has been compiled. Spares must be ordered before AFS - 3-Jun-2017				

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
13464	SDS Equipment Fails During Installation [Window 7]	Event: SDS Equipment fails during or before installation. Cause: All SDS computer components are being prcured at the same time therefore, by the time the parts are installed for U4 refrubi	**Outage Window**		**Window Description**												
			007		007 - SDS1 & SDS2 Mods & Rehab												

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
785	Inadequate schedule detail and work instructions to support the schedule development milestones	Event: Inadequate schedule detail and task development prevents building an accurate detailed schedule. Cause: Many milestones leading to REV 0 issued were missed and pushed beyond their original completion dates. Impact: The schedule will not reflect the true requirement's of the project and could result in work execution slippage or poor work coordination.		Active	Andrew Negenman		28-Feb-17	Monitor	15-Aug-17	3	1	3	9	3	1	3	9
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Draft, Not Started, In Progress Actions associated with the risk.														
788	Readiness of non-refurb funded projects for U2 execution	Event: Lack of readiness to execute AISC non refurb projects. Cause: Disengagement from the milestone and project readiness process for refurb, there is no procedural requirement for the AISC projects to demonstrate completion at the refurb milestone dates. Impact: Potential delays to work program and schedule, impact to critical path.		Active	Andrew Negenman		28-Feb-17	Mitigate	01-Jun-17	4	2	2	8	2	1	3	6
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							
			7823	In Progress	Recovery Plan 2070 : AISC projects	Recovery plan written and executed.	Bill Devlin	Joe Walsh	30-Dec-16	Dec 14th, 2016 - No Change Since Nov 28th Nov 28, 2016 updated attachments with latest status sheet although some progress is being seen, problems remain. The Place holder schedules have been accepted, however things have not been kept up to date and vendor's are not updating the schedule. This has been communicated to the Darlington Projects Execution manager per attached email. 10-June-2016 - NRU2 AISC Project Readiness Matrix (Recovery Plan) file updated and attached to the action.							
			Outage Window		**Window Description**												
			104		104 - Post Feeder Vault Projects												
800	HTS RTS Schedule Risk – Hot Conditioning or HTS Filtering with Fuel in Core	EVENT : Potential Impact of Hot Conditioning with Fuel In-Core is the creation of deposits on the fuel, these deposits could impact Fuel Performance, Core Physics, and Safety Analysis CAUSE: Hot Conditioning when performed with fuel in core has resulted in black deposits at other Candu plants post refurbishment. IMPACT: Black deposits on the fuel would be an unanalyzed configuration in the safety report and could delay unit startup significantly. See NK38-REP-03610-10005 Related issue: Fuel failures due to FME can result in unit outages and increased dose. A rigorous FME program combined with filtration with the fuel in core is the current base case. Qualifying the processes is a condition of fitness for service and a prerequisite to loading fuel.	2	Active	Andrew Negenman		28-Feb-17	Monitor	18-Dec-17	2	4	4	8	2	4	4	8
			Action#	**Status**	**Action Title**	**Action Description**	**Owner**	**Delegate**	**Due Date**	**Comments**							

800	HTS RTS Schedule Risk – Hot Conditioning or HTS Filtering with Fuel in Core	EVENT : Potential Impact of Hot Conditioning with Fuel In-Core is the creation of deposits on the fuel, these deposits could impact Fuel Performance, Core Physics, and Safety Analysis CAUSE: Hot Conditioning when performed with fuel in core has resulted in black deposits at other Candu plants post refurbishment. IMPACT: Black deposits on the fuel would be an unanalyzed configuration in the safety report and could delay unit startup significantly. See NK38-REP-03610-10005 Related issue: Fuel failures due to FME can result in unit outages and increased dose. A rigorous FME program combined with filtration with the fuel in core is the current base case. Qualifying the processes is a condition of fitness for service and a prerequisite to loading fuel.	8826	In Progress	Flush Strainer Progress	Level 1 with all the timelines of the mods is required next week. Complete Determine the need date and work backwards. Develop the plan based on backward planning. Complete Review the plan on Friday - Aug.12, 2016. Complete Next deliverable Conceptual Design is Dec 30/216. ***** Updated following Issues Meeting on 06Feb2017 ****** The conceptual design report was issued and accepted from CEI. This item is also being tracked in Issue # 342 1) Schedule SIM for team on the status of the top design options.2) Prepare for an Executive Options Review Board Meeting (March 15)	Steve Goodchild	Mario Campigotto	15-Mar-17	Heat Transport Filtration/Strainer Design: (Prepared by: Andrew Jeffery) 3 Oct 2016 A Heat Transport Filtration/Strainer Design is to be developed to mitigate risk and help protect the fuel and pressure tubes from debris. · Prepare Engineering Needs Document for Heat Transport Filter/Strainer Design (Complete, NK38-NR-REP-33000-00001 issued; ECR 24638 Approved) · Arrange Staffing Resources for HTS RTS Project (Complete) o Interim Project Manager – Ron McKibbon; MTL – Imran Malik; Interim DTL – Ali Azarbad o Additional DTL & PM interviews are on-going · Kick-Off Meeting for HTS RTS Filter/Straining Strategy – Conceptual Design (Complete as scheduled) · Preparation of Needs Document to support Chemical Addition & Monitoring Skid for Hot Conditioning (Delayed for other project support; Revised Target of Oct 10th, Owner – System Eng) · Preparation of Needs Document to support Pressurizing Skid for Operational Leak Test (Delayed for other project support; Revised Target of Oct 10th, Owner – System Eng) · Develop Design EC Level 1 for HTS RTS Modifications (30 SeptemberTBD) · Investigate waste strategy for removed debris, filters, etc (10 October) · Top Priority à Secure contract and initiate Conceptual Design phase (Contract in place: October 21; CDR complete: December 30th o Prepare Sole Source Justification for qualified vendor (MTL, Supply Chain support needed to expedite contract paperwork) o Arrange Supply Chain support (TCD: Oct 6th)

Outage Window	Window Description
082	082 - RTP Removals, Bridge Replacement
089	089 - HTS Air Hold, Fill & Hydrostatic Test
090	090 - HTS Operational Testing
093	093 - Low Power Testing & Heat-up
095	095 - Run-up & Sync
160	160 - RFR-OPG Scope GSS Defuel
170	170 - RFR- Fuel Load
187	187 - RFR-TMOD Reversal prior to Bulkhead Removal

			Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments							
764	Failure to obtain approval for early HTS Fill	Event: Maintaining current U2EE (P50 and P90) is predicated on filling HTS prior to containment restoration. Cause: At the Operational Decision Meeting (ODM) on June 1st, conditional approval (only) was obtained to allow filling the HTS prior to the restoration of the normal containment boundary. Conditions of approval include follow-up nuclear safety analysis and CNSC approval for a minor revision to an OP&P. Impact: Failure to meet these conditions would add approximately 43 days to the lead-out logic for each unit.	2	Active	Andrew Negenman		23-Feb-17	Mitigate	17-May-17	1	1	4	4	1	1	1	1

761	Failure to obtain approval for early HTS Fill	Event: Maintaining current U2EE (P50 and P90) is predicated on filling HTS prior to containment restoration. Cause: At the Operational Decision Meeting (ODM) on June 1st, conditional approval (only) was obtained to allow filling the HTS prior to the restoration of the normal containment boundary. Conditions of approval include follow-up nuclear safety analysis and CNSC approval for a minor revision to an OP&P. Impact: Failure to meet these conditions would add approximately 43 days to the lead-out logic for each unit.	5389	In Progress	Initiate Moderator RD failure scoping analysis.	Initiate preliminary analysis to establish, for the case of an in core LOCA with bursting of calandria (moderator) rupture discs, the consequences of D2O releases from Moderator and PHT systems, taking into account tritium concentrations in both the moderator and PHT, as well as the release of entrained fission products or other radiological contaminants in the released D2O.	Gerry Martin	Jose Torres	31-Mar-17	AMEC contacted to start scoping out analysis, high level analysis plan and cost and time estimate received. Review of documents generated some comments that need to be resolved before work can progress. TCD changed to Jan 15, 2016 to allow for work scope finalization and analysis to be completed. Restart HIT team formed, meetings being held to narrow down the correct questions to ask contractors to complete the analysis. Contract for the analysis is not yet in-place as scope of required analysis and initial conditions are still being developed. action extended till March 30th - Gerry Martin Jan 8th, 2016. Contract being finalized as scope was recently clarified, no firm TCD from signed contract available, action extended till Aug 30, 2016 - Gerry Martin March 24, 2016 Analysis now underway, new TCD set at Nov 30th, 2016 as work was delayed while scope frozen, computer models were created and required inputs were obtained. Gerry Martin Aug 26, 2016 Analysis is still in progress, and not scheduled to be complete until the new year before it can be reviewed and enter the comment disposition cycle, TCD extended till Feb 15, 2017 - Gerry Martin Nov 11, 2017 Analysis is being finalized. GOTHIC Report R00 has gone through one round of comment and dispositions. GOTHIC Report R01 has been issued for review and acceptance. Dose Assessment Memo R0 is going through comment and dispositions. TCD for this action extended until March 31, 2017 to align with the end date of analysis contract - Jose Torres Feb 14, 2017.

761	Failure to obtain approval for early HTS Fill	Event: Maintaining current U2EE (P50 and P90) is predicated on filling HTS prior to containment restoration. Cause: At the Operational Decision Meeting (ODM) on June 1st, conditional approval (only) was obtained to allow filling the HTS prior to the restoration of the normal containment boundary. Conditions of approval include follow-up nuclear safety analysis and CNSC approval for a minor revision to an OP&P. Impact: Failure to meet these conditions would add approximately 43 days to the lead-out logic for each unit.	5390	In Progress	Impact of non-tritium HTS radionuclides	Ensure that spill analysis for the HTS fill scenario includes an assessment of the effect of entrained contaminants or provides a limiting value.	Gerry Martin		17-Apr-17	Analysis for the D2O contingency storage project is being reviewed to determine if that analysis can be used to respond to this action. Quantification of what possible contaminants could be present in the PHT coolant may prove difficult and would need some bounding assumptions. The present analysis assumed dose came from tritium gas escaping the reactor vault, and did not assume any liquids escape. Solid contaminants would not likely escape from the vault as they are heavy, non-soluble and would stay with the liquid, and not exit the RV with the tritium gas. C-14 may be presents, but typically, the dose from tritium is 7 times that from C-14 for scenarios such as this one. TCD extended to Jan 15, 2016 to allow for D2O storage tank work to be completed and finalized - to determine applicability to this situation. Restart HIT team formed, meetings being held to narrow down the correct questions to ask contractors to complete the analysis. Contract for the analysis is not yet in-place as scope of required analysis and initial conditions are still being developed. action extended till March 30th - Gerry Martin Jan 8th, 2016 Contract being finalized as scope was recently clarified, no firm TCD from signed contract available, action extended till Aug 30, 2016 - Gerry Martin March 24, 2016 Analysis now underway, new TCD set at Nov 30th, 2016 as work was delayed while scope frozen, computer models were created and required inputs were obtained - Gerry Martin Aug 26, 2016 Analysis is still in progress, and not scheduled to be complete until the new year before it can be reviewed and enter the comment disposition cycle, TCD extended till Feb 15, 2017 - Gerry Martin Nov 11, 2017 Analysis continues to be in progress, but is taking longer than anticipated. TCD extended till April 17, 2017 - Gerry Martin Feb 17, 2017

761	Failure to obtain approval for early HTS Fill	Event: Maintaining current U2EE (P50 and P90) is predicated on filling HTS prior to containment restoration. Cause: At the Operational Decision Meeting (ODM) on June 1st, conditional approval (only) was obtained to allow filling the HTS prior to the restoration of the normal containment boundary. Conditions of approval include follow-up nuclear safety analysis and CNSC approval for a minor revision to an OP&P. Impact: Failure to meet these conditions would add approximately 43 days to the lead-out logic for each unit.	5391	In Progress	Assessment of spill volume and rate	The analysis is to include an assessment of maximum volume of tritiated D2O that may be released in the event of an accident, the maximum rate of release that may be experienced and the impact of that volume/rate on the proposed release mitigation strategy.	Gerry Martin		17-Apr-17	Assessment of total spill volume is underway and argument to be supported is that there is enought spill capacity containment in the vault that water will not be exiting the RV. TCD extended to Jan 15 2016 due to completing prioirties of Aug 15 design milestone and now DNGD VBO support. Restart HIT team formed, meetings being held to narrow down the correct questions to ask contractors to complete the analysis. Contract for the analysis is not yet in-place as scope of required analysis and initial conditions are still being developed. action extended till March 30th - Gerry Martin Jan 8th, 2016 Contract being finalized as scope was recently clarified, no firm TCD from signed contract available, action extended till Aug 30, 2016 - Gerry Martin March 24, 2016 Analysis now underway, new TCD set at Nov 30th, 2016 as work was delayed while scope frozen, computer models were created and required inputs were obtained. Gerry Martin Aug 26, 2016 Analysis is still in progress, and not scheduled to be complete until the new year before it can be reviewed and enter the comment disposition cycle, TCD extended till Feb 15, 2017 - Gerry Martin Nov 11, 2017 Analysis continues to be in progress, but is taking longer than anticipated. TCD extended till April 17, 2017 - Gerry Martin Feb 17, 2017							
			5392	In Progress	Submit OP&P revision request with supporting analysis to CNSC	Submit safety assessment information as required to support the revision of OP&P to allow HTS to be pressurized while the refurbishment unit is disconnected from Containment.	Gerry Martin		16-Oct-17									
			Outage Window		**Window Description**														
			089		089 - HTS Air Hold, Fill & Hydrostatic Test														
791	Refurbishment project not properly accomodated in the Generation Plan	Event: Outage schedule and planned generation does not currently take into account the shared O&M and vendor support for the outages at PNGS and DNGS. Cause: Refurbishment project reflected on the long range generation plan only as a high level place keeper. Impact: Potential unnavailability of critical resoruces or vendors during peak demands due to scheduled overlaps.	4	Active	Andrew Negenman		28-Feb-17	Monitor	31-Mar-17	2	1	2	4	2	2	1	4		
			Outage Window		**Window Description**														
			000		000 – No Window Related														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
798	Higher Than Expected CSA Demand for U134	Event: Assumptions about CSA demands for Units 134 are lower than potentially required. Cause: RQE reflects requirement for 8.5 CSA's post 2018. This is due to an assumption that demand will drop after unit 2. Impact: Inability to support units 134 with the same # of CSA's required for Unit 2. 11 CSA's were required to support the prereq and execution readiness preparedness work on unit 2, this was documented in CCF 812.	1	Active	Karen Fritz	Vijay Santhanam	10-Feb-17	Monitor	31-Mar-17	2	2	1	4	2	2	1	4		
			Outage Window		**Window Description**														
			000		000 – No Window Related														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																
810	Data Integrity resources and oversight insufficient to meet the extensive needs of maintaining data integrity of IDB.	Event: Many data sources compound data gathering and reporting ease for refurb. Cause: IDB pulls from 22 separate databases to bring the data into one central place for the purposes of producing reports and metrics. Impact: Inaccurate reporting on status and progress of outage, this includes trending and tracking.	4	Active	Karen Fritz	Ron Hall	13-Feb-17	Monitor	19-Apr-17	2	2	2	4	2	2	2	4		
			Outage Window		**Window Description**														
			000		000 – No Window Related														
			There are no Draft, Not Started, In Progress Actions associated with the risk.																

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

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Data Refreshed: 07-Mar-17 10:30 PM

776	Critical path Impact of HTS Pump Motor Changeout	Event: PHT motor lifts over the vault, motors must be removed and replaced during refurb outage. Cause: Weight of motor exceeds safe load level above the vault while workers are in the room. Impact: Potential delays to critical path, clearing the vault and stopping RFR work while lifts are in progress.	3	Active	Andrew Negenman	Barry King	10-Feb-17	Monitor	31-Mar-17	2	1	1	2	2	1	1	2

Outage Window	Window Description
022	022 - Remove PHT Pump Motors

There are no Draft, Not Started, In Progress Actions associated with the risk.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 07-Mar-17 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
561	Availability and Retention of Project Leadership	Risk pertains to securing and retaining project management leadership talent which could impact on our ability to execute Refurbishment.	3	Active	Candice Kay		24-Feb-17	Mitigate	29-Sep-17	3	3	3	9	3	3	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
3306	In Progress	PPR Health & Development Planning 4.4	Knowledge Management Transfer development planning - critical for ongoing success	Candice Kay		29-Sep-17	· PPR for 2017 to be aligned with Project Excellence goals - cascade to all staff. · Staffing Plan to be approved/finalized · Project Management Capability Builder - Plan in place as per Project Management Peer Team
9523	In Progress	Longevity Strategy	The project is 10 plus years and during this time we will lose critical leaders. Complete the following tasks: Redesign organization to provide ability to sustain work and to transfer knowledge. Launch PMCD to create future leaders. PDIT - Project Director In Training - to secure & retain future leaders.	Candice Kay		30-Jun-17	Redesign organization to provide ability to sustain work and to transfer knowledge. Launch PMCD to create future leaders. PDIT - Project Director In Training - to secure & retain future leaders. Targeted external hiring for key leadership roles Increased focus on development planning

Outage Window	Window Description
083	083 - Lower Feeder Installation
118	118 - CT Install Series
119	119 - Fuel Channel Install Series

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current				Post			
										Probability	Financial	Schedule	Score	Probability	Financial	Schedule	Score
959	Augmented Staff Hiring and Re-Hire Process	Event: Augmented Staff and Re-Hire procedure, in some cases, is causing a delay which may impact our ability to attract and retain key individuals to support Refurbishment. Case: Recent revision of OPG Re-Hire and Augmented Staff procedure is causing potential delays in staffing process and limiting available resources. Impact: Potential cost impact if unable to hire and retain key individuals to support the project.	3	Active	Candice Kay	Candice Kay	24-Feb-17	Mitigate	31-Mar-17	2	3	3	6	1	1	2	2

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
9954	In Progress	Review OPG Augmented Staff and Re-Hire Procedure	Integrated team is in place to review the OPG Augmented Staff and Re-Hire Procedure. Representatives from various NR organizations are members of the team.	Candice Kay		31-Mar-17	Initial results will be provided in early March 2017.

Outage Window	Window Description
000	000 – No Window Related

UNDERTAKING J6.1

Undertaking

To provide the location in the evidence of the risk register Dr. Galloway reviewed.

Response

See Tr. Vol. 6, p. 78, lines 2-6.

UNDERTAKING J7.1

Undertaking

To provide a revised version of Exhibit K7.1 more tailored to the DRP.

Response

The following response was provided by Schiff Hardin:

The following is a description of proposed structure and content for a periodic report regarding the status of the Darlington Refurbishment Program (DRP) to be provided by Ontario Power Generation (OPG) to the Ontario Energy Board (OEB) and other governmental and/or regulatory stakeholders. The exact structure and content of the report should be determined based on what is necessary for OPG to accurately and transparently report the status of the DRP including any actual or threatened risks to budget and schedule. The structure of the report can vary from the order listed below as long as all of the categories of information are adequately and transparently addressed. The overall benchmark of an effective OPG report to the Ontario Energy Board (OEB) and other governmental and/or regulatory stakeholders is that which provides sufficiently detailed and transparent information so that the recipients understand: (1) what is going on at the Darlington site including known and potential risks to budget and schedule; (2) the technical, commercial, schedule, safety, quality or other risk management challenges facing the DRP; and (3) the actions OPG is taking to mitigate risk, respond to issues as they arise, and make project management decisions.

PROPOSED STRUCTURE & CONTENT OF PERIODIC DARLINGTON REFURBISHMENT PROJECT (DRP) PROGRESS REPORTS

Section 1 **Introduction and Table of Contents**. This section should provide an explanation of the business, legal, technical, and regulatory context and requirements governing the DRP including any legal, governmental, and/or regulatory requirements governing the purpose, structure, and content of the report.

Section 2 **Executive Summary**. This section should provide a high level overview of the current status of the DRP. This section should be previewing and summarizing the content provided in more detail in the remaining sections of the report.

Section 3 **Overall Darlington Refurbishment Program (DRP) Status.** The purpose of this section is to provide a substantive update regarding the status of every project and/or work bundle included in the Darlington Refurbishment Program.

The narrative should be detailed enough for the recipients to gain an accurate understanding of the current status of each of the components of the DRP including discussion and analysis of not only the events that occurred during the reporting period, but a forecast of anticipated challenges and OPG's mitigation efforts.

The exact content of this section and scope of the narrative should evolve and change over the life cycle of the DRP. The consistent metric that OPG should use to evaluate the appropriate reporting content throughout the DRP should be the content and narrative necessary to accurately and transparently report the status of the DRP including opportunities, challenges, risks, and the contemporaneous evaluation of what lies ahead. The reporting should be based on OPG memorializing not just the facts as they occur, but the steps of the process the management team and corporate leadership are using to make project management decisions for all significant technical, cost, schedule, safety, quality or other challenges to the DRP.

For example, as appropriate for the phase of the Program, the discussion of the overall status of the DRP should include the following:

- Overview. This section should put the current reporting period in context of the overall DRP and provide a roadmap of the substantive discussion in the remainder of the section.

- DRP Progress Update. This should include a report of all contractor/vendor performance during the reporting period and a discussion of the events occurring during the reporting period for each project or work bundle included in the DRP. Accordingly, the exact content will change over the life of the DRP. Additional subtopics may be appropriate based on the actual facts and events that occur over the life cycle of the DRP. The list below is not an exclusive list but serves as a recommended framework to communicate sufficient content to transparently and accurately report the status of the DRP.

    - *Engineering Status*. As applicable, the report should include a discussion of the status of any engineering work performed including the status of engineering deliverables and forecast for next period. The discussion should address all variances and include engineering earned value metrics including planned, earned and actual hours. Engineering staffing plan should be

discussed including comparison of planned to actual staffing. The report should address any engineering problems, challenges, concerns and OPG's mitigation efforts.

- *Procurement Status*. As applicable, the report should include a discussion of procurement activities performed by OPG and/or the contractors during the reporting period and forecasted for the next period. This would include a discussion of the status of major material and equipment purchases and a discussion of all variances to budget and/or schedule. This also includes reporting on major supplier inspections that are planned, scheduled, and/or completed. The report should address any procurement problems, challenges, concerns, and OPG's mitigation efforts.

- *Construction Status*. The report should include a discussion of construction activities performed by OPG and/or the contractors during the reporting period and forecasted for the next period. This includes a report of major accomplishments this period and planned major accomplishments for next reporting period and a discussion of all variances. The discussion should address earned value metrics including a discussion of any negative trends or low productivity and the details of the planned, earned, and actual manhours; an update of material delivery and installation including an identification of any shortages, deficiencies, and problems; discussion of the status of major subcontractors including, but not limited to, those active at site, new mobilization, demobilization, and any problems and concerns; major equipment mobilization, demobilization, usage and utilization; manpower by trade and Contractor/Subcontractor; and any labor relations issues, quality, environmental and permitting concerns, as applicable. All work packages should be identified and tracked from engineering to procurement to construction completion and start-up.

- *Testing, Start-Up, and Commissioning*. As applicable, the report should include a discussion of testing, start-up, and commissioning activities performed by OPG and/or the contractors during the reporting period and forecasted for the next period. This includes a report of major accomplishments this

period and planned major accomplishments for next reporting period and a discussion of all variances. The discussion should address earned value metrics including a discussion of any negative trends or low productivity and the details of the planned, earned, and actual manhours; identification of any shortages, deficiencies, and problems; and discussion of test results.

- o *Other*. OPG should include any other major topics/activities necessary to explain the DRP status for the reporting period. This could include safety issues, environmental issues, quality assurance and quality control concerns, force majeure events, staffing problems, potential regulatory issues, or other events occurring during the reporting period.

- Key DRP Program Risks & Risk Management. The major categories of risk to the DRP should be identified and discussed including an analysis relevant events and/or mitigation measures taken during the reporting period. Discussion of any problems OPG or the contractors encountered during this period or anticipated problems in upcoming periods. As applicable, OPG should discuss the results of prior improvement/mitigation actions undertaken. Either this section or the previous section should include a discussion of significant contractor claims, disputed change orders, and/or other significant commercial issues.

- Safety & Quality Reporting. Industry standard safety and quality metrics should be provided in this section to give the reader an idea of how the DRP overall and the individual contractor's safety and quality record compares to industry standards and OPG expectations and goals. Regarding safety, the narrative should include an explanation of all safety related incidents, a discussion of any lost man hours due to accidents, an explanation of any safety programs or initiatives launched by OPG or the contractor(s), and any safety investigations, reports, fines/penalties undertaken during the reporting period. Regarding quality, the narrative should include a summary of contractor/vendor quality performance including analysis of the amount of rework, rejection rates, etc.

- Financial Reporting. This section should provide a narrative and

graphics addressing the planned, actual, and projected costs of the DRP including sufficient detail to see the component projects. OPG should discuss all variances between actual costs and the DRP budget and the current forecast and cost trends. Cost discussion may also include invoicing status for major contractors. The cost details should be provided in attachments to the report. The actual format and content of financial reporting required by government or regulatory bodies is typically determined by the utility company's cost control software and internal reporting created in accordance with existing corporate and/or project-specific policies and procedures. The reports generated internally for managing the project are typically required to be transparently provided as a part of any ongoing reporting requirement.

- Schedule Reporting. This section should provide a narrative addressing the overall schedule status of the DRP including at least three critical paths. The report should identify all major interim and/or completion milestones achieved. The report should address key activities for each major work bundle during the reporting period. This should include an earned value summary and conclusions for the entire DRP as well as earned value data broken down by the major work bundles and contractors. Accurate reporting of earned value should discuss not only the current reporting period, but the project to date. It is common for graphics to be used as a part of the report – typically attached as an Exhibit. The report should compare the current DRP schedule to baseline schedule and include a narrative of known or suspected problem areas which have affected or may affect the current project schedule and all recovery and mitigation plans. The actual format and content of schedule reporting required by government or regulatory bodies is typically determined by the utility company's schedule software and internal reporting created in accordance with existing corporate and/or project-specific policies and procedures. The reports generated internally for managing the project are typically required to be transparently provided as a part of any ongoing reporting requirement.

- OPG Staffing. This section should address OPG's actual staffing levels as compared to the plan and address any variances to the plan, changes to the staffing plan, efforts to fill open positions, and identify any leadership turnover.

Suggested Report Attachments:

Cost Report(s) Covering the Reporting Period
Earned Value Metrics by discipline and area
Level 1 Schedule Planned and Current comparison
Level 2 Schedule Planned and Current comparison
Supplemental exhibits, as appropriate.
Audit reports for all audits performed during the Reporting Period
Third-party oversight reports submitted to OPG during the Reporting Period

UNDERTAKING J7.2

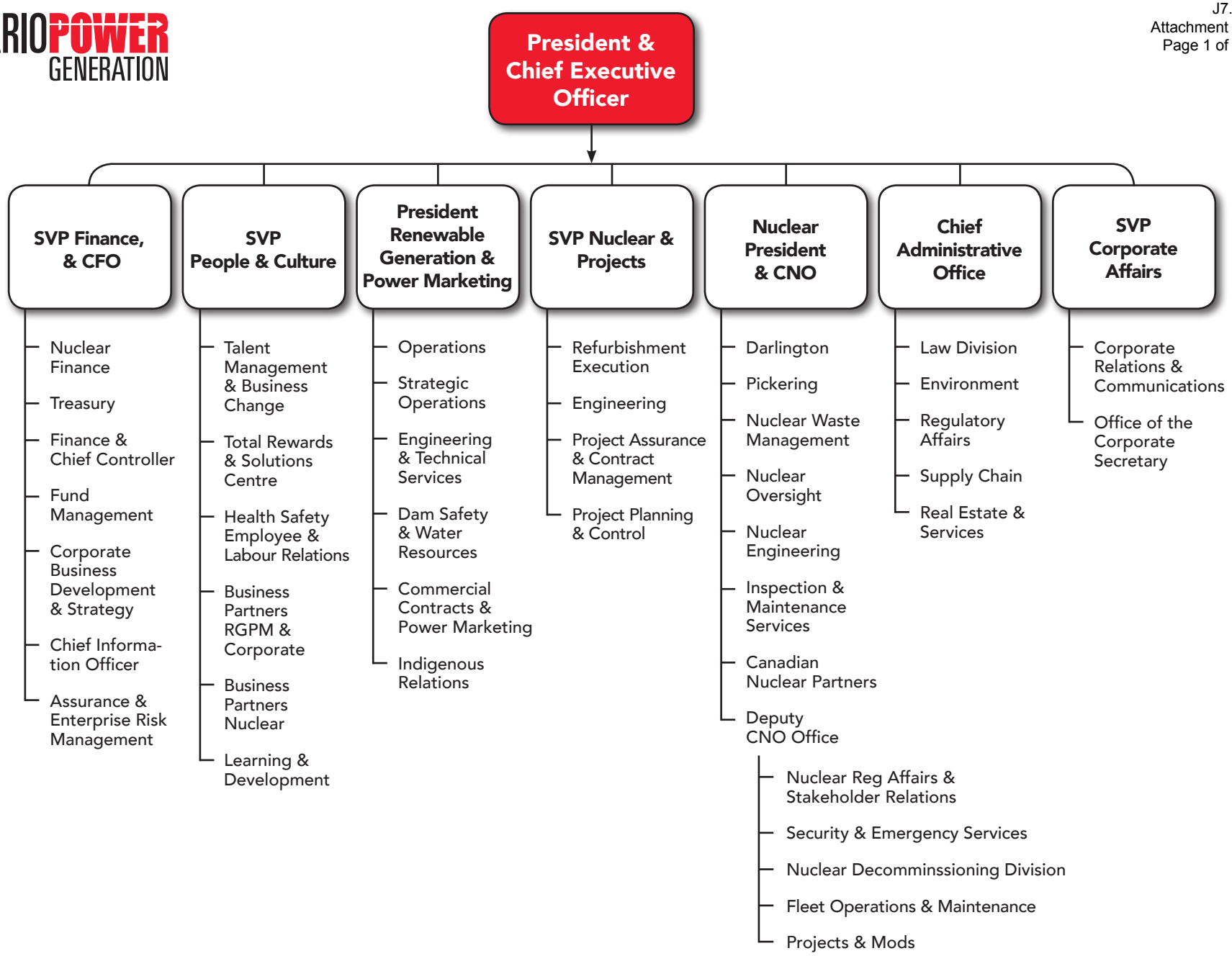
Undertaking

To file an updated org chart for OPG.

Response

Attachment 1 provides the updated organizational chart for OPG.

ONTARIO POWER GENERATION



Effective March 10, 2017

UNDERTAKING J7.3

Undertaking

To provide a copy of the report ARC 2016 Q1: Project Controls - Projects & Modifications ("P&M") Group, if possible before Panel 3A appears.

Response

The Project Controls Audit – Projects & Modifications Group Internal Audit report is filed as Attachment 1. In addition, consistent with OPG's response to L-4.3-1 Staff-072, please see Attachment 2 for a summary of the findings and the associated status of the management action plans.

ONTARIO POWER GENERATION

Internal Audit

Project Controls Audit - Project & Modifications Group

March 9, 2016

Report Rating: **Requires Improvement**

Distribution:

Dietmar Reiner
SVP, Nuclear Projects

Art Rob
VP, Projects & Modifications

cc:	Jeffrey Lyash	President & Chief Executive Officer
	Glenn Jager	Chief Nuclear Officer
	Carlo Crozzoli	SVP and Acting Chief Financial Officer
	Steve Woods	SVP, Nuclear Engineering and Chief Nuclear Engineer
	Carla Carmichael	VP, Nuclear Finance
	Jody Hamade	VP, Enterprise Risk Management
	Gary Rose	VP, Project Planning & Controls
	Riyaz Habib	Director, Contract Mgmt. & Project Control Office
	Sabine Parks	Director, Nuclear Finance
	Janice Ding	Director Internal Audit
	Art Maki	Director Nuclear Oversight

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1.0 EXECUTIVE SUMMARY

1.1 Summary of Internal Audit Findings

Report Rating: **Requires Improvement**

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	Project estimates are not at a sufficient level of accuracy prior to the execution phase.	Financial	x		
2	Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved project changes.	Operational		x	
3	A Gating Process for AISC Portfolio Projects has not been formally implemented.	Operational		x	
4	Governance and Procedures specific to AISC projects require improvement.	Operational			x
Total			**1**	**2**	**1**

1.2 Background

The Projects and Modifications ("P&M") Group, part of the Nuclear Projects Organization, is responsible for the management and execution of Operations, Maintenance and Administration ("OM&A") and Capital Projects supporting the Darlington and Pickering Nuclear Generating Stations and Western Waste Facility. The P&M Group has a total project portfolio of $1.1B over the three year period from 2015 through to 2017. The projects that the Asset Investment Steering Committee ("AISC") manages total $833M, with the remaining portfolio related to projects supporting the Darlington Nuclear Refurbishment ("DNR") Project. DNR Projects are executed using the Nuclear Project's Project Management framework which has different requirements than is currently used on the AISC projects, which follows Finance governance. To address these differences, a "Project Excellence" initiative is now in place and includes the development of a common set of standards for all projects across Nuclear. This initiative had just started at the time of the audit.

The AISC is a committee that meets to review, prioritize and provide budgets for sustaining projects for OPG's Nuclear Generating Stations. The committee works in conjunction with business line sponsors to prioritize and recommend projects for approval in accordance with business objectives.

Given the high value of P&M's AISC project portfolio and the critical role these projects play in OPG's on-going nuclear operations, this audit was performed as part of Internal Audit's ("IA's") cyclical audit program.

[1] Please refer to Appendix D for risk rating definitions

1.3 Audit Objective & Scope

The objective of this audit was to assess the design and operational effectiveness of project management controls implemented by the P&M Group to support timely completion of the current portfolio of AISC projects in a manner that achieves project goals.

The scope of the audit included a review of processes and testing, on a sample basis, to determine whether:

A. Governance & Procedures

1. Policies and procedures for project control processes have been established and reflect current practices;
2. Roles and responsibilities for project control processes have been clearly defined.

B. Planning

1. Each project has a valid Business Case Summary ("BCS") which has been approved by the ASIC;
2. A Project Charter and Project Management Plan ("PMP") has been developed, approved, and communicated;
3. The project scope has been clearly defined, with the input of key stakeholders and approved;
4. An appropriate Work Breakdown Structure ("WBS") has been developed which identifies all work to be performed by the project and its deliverables;
5. A schedule has been created that considers resource requirements;
6. The schedule is structured in accordance with the project's WBS, built upon the logical division of work by cost accounts, work packages;
7. The schedule integrates and identifies interdependencies between activities, including critical path as appropriate;
8. Costs are planned, structured, controlled and reported based on the project's WBS, Cost Accounts, and Work Packages;
9. Risks are formally identified with mitigation plans and managed with periodic reviews and updates throughout the project; and
10. Contingency amounts are assigned, formally tracked and appropriately approved when released.

C. Execution

1. Schedule monitoring and control has been established on the project;
2. Schedules are updated on a timely basis and accurately reflect the current status of all deliverables, activities, interdependences and timelines across the project;
3. Performance Metrics have been adopted on the project and are reported to management (e.g. Schedule Performance Index, Cost Performance Index, etc.);
4. The project has a material procurement schedule or tracking sheet representing the receipt of materials, equipment and prefabricated items;
5. Scope, cost, schedule, and contingency changes are managed and approved through a change management process;
6. Forecasts are generated and reviewed for expected variances to plan;
7. Completion of work packages is validated including quality requirements;
8. Projects are executed in accordance with OPG's quality requirements; and
9. Projects are assessed for completeness of scope, cost, schedule and quality objectives, and approved by project sponsors prior to close-out.

D. Reporting

1. Costs are accurately coded to projects to allow for proper tracking;
2. Cost, quality and schedule performance is accurately measured and reported to management on a timely basis. Variances and mitigation efforts to recover on these variances are explained and reported in a complete fashion;
3. Post-implementation reviews are performed to validate that completed projects have met their objectives and to gather lessons learned for future projects; and
4. System access to reporting systems are controlled and monitored.

The scope of the audit included an evaluation of thirteen projects (see Appendix A) from P&M's AISC Portfolio up to the end of September, 2015. Projects were selected based on size, facility, and phase to ensure a cross-section of the population.

1.4 Conclusion

Positive Observations

- The P&M Group is in the process of implementing several changes to their project management framework to align with the revised Nuclear Projects governance, including adopting more up-front planning activities prior to execution; and

- The P&M group's project management team were found to be highly knowledgeable concerning project management principles and how to deploy them on their projects.

Key Findings and Recommendations

The audit has noted the following key findings:

- Project scope definition and estimate accuracy is sometimes insufficient for the start of a project's execution phase. This has caused significant variances to project estimates on several AISC projects. The P&M group should ensure, through implementation of its new gating process, that an AACE[2] Class 3 or better estimate for the project is developed, approved and established as a baseline prior to the start of execution phases. The amount of contingency should reflect risks, including the confidence in and the class of estimate;

- Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved changes in Business Case Summaries ("BCS's") and Project Change Request Authorization Forms ("PCRAF's"). The P&M Group should evaluate resource requirements and work with its vendors to ensure proper CSCB's are deployed prior to starting work. In addition, a review of the project change management processes should be undertaken as considerable amount of time is required to get approval for changes;

- The plan to change to the Gated Process for AISC Portfolio Projects to facilitate oversight, phased approval and release of project funds has not been fully implemented. The Nuclear Projects group should work with the AISC Chair in the implementation of a gating process for AISC projects, clearly defining the requirements for each gate; and

[2] Association for the Advancement of Cost Engineering ("AACE").

- There are gaps in governance and procedures. For example a Terms of Reference ("TOR") document for AISC should be finalized and reporting for cost and schedule performance should be standardized.

The findings noted in the report have been reviewed with management who has committed to specific action plans to address them. Please refer to Section 2.0 for details of the above findings along with the potential causes, impacts, recommendations and management action plans.

Opportunities for improvement

The P&M group should look at:

- Expanding its use of Earned Value ("EV") techniques such that cost and schedule variances are explained formally by work package, and Cost Performance Index ("CPI") values take on a greater role in cost and forecast management. At present, use of EV techniques have not been fully implemented for AISC projects, although the plan is to implement EV techniques going forward on all new 2016 projects;

- Improving the Contingency Management process utilized in AISC projects such that specific contingency is established and tracked on a per-risk basis. Contingency Tracking Logs should be used to monitor the allocation of contingency on an on-going basis. The confidence level associated with the class of estimate at the various release phases should be considered in contingency development. Management should also review the assignment and ownership of contingency for monitoring and releases; and

- Improving housekeeping efforts on Risk Registers such that risks and risk action items are closed in a timely manner.

2.0 DETAILED AUDIT FINDINGS

1. Project estimates are not at a sufficient level of accuracy prior to the execution phase.	**High**

As per OPG's BCS requirements and the Association for the Advancement of Cost Engineering ("AACE") standards, cost estimates should be developed to at least a Class 3 estimate prior to execution (see Appendix B). For certain projects, a Class 2 estimate may be used as a "check estimate" once construction work packages are complete and just prior to the start of field execution to confirm accuracy of the Class 3 estimate submitted as part of the Execution Phase BCS. In order to come to a more precise estimate, detailed engineering must be substantially complete to determine material and labour requirements.

It was noted that of the six projects sampled in the execution phase, all six projects did not have an Estimate at Completion ("EAC") for the project established at either a Class 3 or Class 2 level and they were still performing detail engineering work while in their execution phase. In some cases, the true EAC value for the entire project is not identified until the project is in the advanced stages of execution when a significant portion of the execution costs have already been incurred. (Refer to Appendix A for sample projects reviewed in the execution phase).

Potential Causes & Impact

Potential Cause:

- The current AISC process, which utilizes Finance Governance, does not mandate the establishment of at least an AACE Class 3 estimate prior to the start of execution governance allows for execution to be released with different class of estimates;
- Business Case Summary documents and governance does not require clearly identifying the class of estimate and the range for the potential costs for the current release and the total project;
- Contingency assigned does not always fully address potential variances associated with the class of estimate;
- Lack of a formal gating process and clear definition of gate requirements; and
- Station requirements for "fast tracking" of projects to address emergent issues.

Impacts:

- Growth in project estimate-at-completion values through the execution phase of the project;
- Insufficient budget assignments when entire cost of project is not defined prior to execution, potentially resulting in deferrals or cancellations of other downstream projects; and
- The decision process to proceed with projects may be based on inaccurate cost/benefit analysis when releases are sought with incomplete cost information.

Recommendations	Management Action Plan	Owner & Target Completion Date
Management should ensure sufficient detailed engineering is completed in the definition phase to yield at least an AACE 3 estimate prior to start of execution and factor in potential variability associated with the class of estimate when establishing contingency in the various phases of the project. The BCS's and reporting of EAC for Definition Phase should provide the approving authorities with the understanding of the ranges of estimate for the release and the total project.	As part of the Nuclear Projects "Project Excellence" initiative, an estimating Centre of Excellence ("COE") is now in place within the Planning and Project Controls group; all 2016 AISC Project New Starts greater than $5 Million will require estimate review by the COE, consistent with the Gated process (See Finding 3). Gated process will also provide increased oversight in the release phase of projects and cost and estimate accuracy and contingency management.	Gary Rose VP Planning and Controls April 30, 2016

2. Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved project changes.	**Moderate**

Cost and Schedule Control Baselines ("CSCB's") are the primary control for measuring cost and schedule performance on a project. When setup correctly (i.e. Built upon reliable project estimates and front-end planning), they provide an indication of which work packages on a project are ahead or behind on cost and schedule performance, the magnitude of these variances and their net impact on the overall project.

CSCB's on three out of 13 projects sampled were found not to be keeping pace with cost and schedule baseline changes being requested and approved in Business Case Summaries ("BCS's") and Project Change Request Authorization Forms ("PCRAF's"). The reliability of contractor data has contributed to this issue. This lack of accurate and timely data has contributed to Cost Performance Index ("CPI") measurements being skewed at work package levels.

In addition to the above, two of the projects were found to be without CSCB's entirely. The P&M group has indicated that they are in the process of implementing project planning and control protocols with their Engineer-Procure-Construct ("EPC") vendors to ensure vendor schedules are received at the start of projects and that CSCB's are created, beginning with new project starts for 2016.

Potential Causes & Impact

Potential Causes:

- Less than adequate front-end planning due to a substantially larger work program executed in short time frame;
- Contractors are not providing accurate cost and schedule information as required by the contract. Therefore, cost and schedule are being updated through PCRAFs and BCS' by OPG Cost and Schedule Analysts ("CSA's") who are challenged to keep up with increasing changes;
    - CSA resources are constrained due to competing priorities associated with processing numerous BCS and contingency releases;
- Some station priority projects are fast-tracked with reduced front-end planning that may result in increased changes later in the project; and
- Difficulty incorporating vendor schedules within CSCB's due to the significant volume of scope changes.

Impact:

A CSCB is the primary control mechanism used to manage and control cost and schedule performance on a project. The absence of a current and realistic CSCB may result in potential cost increases and schedule delays.

Recommendations	Management Action Plan	Owner & Target Completion Date
Management should: • Review workloads of CSAs and evaluate resource requirements; • Work with contractors to ensure proper CSCB's are deployed prior to starting work; and • Review the current BCSs and PCRAF approval processes to reduce time for approvals.	P&M is reviewing the Project Controls work processes executed by CSAs in planning and controlling projects and the amount of project work which will be executed by P&M through the Business Plan period. This information will help in determining the resource gap with CSAs. Once the gap has been determined, an appropriate resourcing strategy will be implemented. This review will include the review of BCSs and PCRAF approval processes to determine opportunities to reduce time of approval.	Jamie Lawrie Director, Project Controls September 30, 2016

3. A Gating Process for AISC Portfolio Projects has not been formally implemented.	**Moderate**

A gating process is meant to define a clear list of requirements, deliverables, and expectations a project should follow in order to be granted approval to proceed to its next phase within the typical five phases of a project's life cycle.[3] In addition to the above, a robust gating process also requires that a project be defined and associated work scope be estimated to specified levels of accuracy.

Although the AISC acts as a de facto Gate Review Board for AISC projects, the gating process outlined in the Nuclear Projects governance (N-STD-AS-0028) and Project Management Manual (N-MAN-00120-10001-GRB) has not been fully implemented for AISC projects. At present, the primary control used for gate approval between phases in the AISC project life cycle is the BCS process. While this is an important requirement, the BCS process does not constitute a complete list of all the deliverables required at each gate approval, nor formalize the challenge process that should take place regarding the approval of each deliverable. Management has indicated that they are in the process of formalizing a gating process for AISC projects in Q1 2016.

Potential Causes & Impacts

Potential Cause:
The new Nuclear Projects governance and procedures are high-level principle-based documents which do not specifically address AISC requirements.

Impact:
Potential for cost increases and schedule delays due to insufficient independent oversight and control of project activities and objectives.

Recommendations	Management Action Plan	Owner & Target Completion Date
Management should: • Complete its plans to develop and deploy a formal gating process for P&M use on AISC projects; • Ensure gate review documentation packages are created and maintained as a key part of the gate-approval process; and • Ensure that formal gate reviews and approvals are performed and that required stakeholders such as Finance are involved in the gate review and challenge process.	The Nuclear Projects Gated process will become the standard approach for P&M AISC projects beginning with 2016 Project New Starts. This change has been approved by the SVP/CNE and VP, P&M and an initiative is underway to align and implement the Gated process. Finance will be involved in the gate review process. Implementation requires the following actions: 1. Establish a common Gated process for all Nuclear Projects. 2. Through a Change Management Plan, prepare and issue desktop guides for Project Life Cycle to AISC Members and Project Managers. 3. Preparation and Issuance of AISC Terms of Reference to AISC Members and Project Managers.	Actions #1 and #2: Gary Rose VP Planning and Controls April 30, 2016 Action #3: Steve Woods SVP & CNE April 30, 2016

[3] The five standard phases in a project life-cycle are Identification, Initiation, Definition, Execution and Closeout.

4. Governance and Procedures specific to AISC projects require improvement.	**Low**

There are three key gaps identified in governance and procedures that should be addressed:

1. A formal Terms of Reference ("TOR") document does not exist to govern the role, accountabilities, and operation of the AISC;

2. Although Nuclear Projects Governance should apply to AISC funded projects, this principal is not adequately documented as AISC projects follow existing Finance governance. To reduce this confusion, some AISC specific processes should be defined including:
   - The scope and change management process involving PCRAF's should be substituted with the current process in Nuclear projects called CCF;
   - The gating process, including the requirements and deliverables for each gate; and
   - The process for establishing and integrating vendor schedules, establishing forecast inputs, work breakdown structure requirements, etc.

3. Requirements for month-end performance reports and record keeping are undefined. Each project manager runs their project using a different set of month-end reports and reports are not formally stored by project in a central directory for future reference.

Potential Causes & Impact

Potential Cause:
The new Nuclear Projects governance and procedures are high-level principle-based documents which do not specifically address AISC requirements.

Impacts:
- Potential for confusion amongst project team members on how to handle AISC specific requirements versus other DNR requirements; and
- Potential for cost increases and schedule delays due to ineffective planning and control of project activities and objectives.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should: 1. Formalize a Terms of Reference document for the AISC; 2. Formalize requirements specific to AISC Project Management; leveraging Nuclear Project's governance where possible; and 3. Standardize the reporting for AISC projects and store these in a centralized repository for future reference. i.e. Book of Record.	Recommendations 1 and 2: Action plan for Finding 3 will include issuance of AISC Terms of Reference and a desktop guide to assist projects under AISC authority in the use of Nuclear Projects Governance, specifically the gated process. Recommendations 3 and 4: Nuclear Projects is in the process of developing standardized reports using Ecosys. Phase 1 implementation will be in Nuclear Refurbishment and Phase 2 will be in P&M.	Recommendations 3 and 4: Gary Rose VP Planning and Controls December 31, 2016

APPENDIX A – LIST OF PROJECTS REVIEWED

Item	Project No.	Project Description	Project Area	Current Project Phase	Current EAC (CDN$M)
1	31412	DN Class II UPS Replacement	Darlington	Execution	55.099
2	31422	DN Pressurizer Heaters & Controllers Replacement Project	Darlington	Execution	14.511
3	31426	DN F/H Inverter Replacement	Darlington	Execution	14.386
4	31508	DN Fukushima Phase 1 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	Darlington	Execution	58.391
5	31710	DN Shutdown Cooling Heat Exchanger Replacement	Darlington	Execution	56.085
6	80058	NWM Western Waste Management Facility Groundwater Monitoring Network	NWM	Execution	4.710
7	33623	DN Installation of partial discharge monitors	Darlington	Close-out	7.147
8	40682	PB MOT8 Foundation Settlement	Pickering	Close-out	3.844
9	60144	IC-18's/IC-HX's	NWM	Close-out	9.730
10	40990	PN Bay Module Loader PLC Replacement	Pickering	Definition	1.200
11	41027	PN Fukushima Phase 2 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	Pickering	Definition	46.302
12	38419	DN Capping of D2O Collection Lines	Darlington	Definition	8.398
13	31516	DN Station Lighting Retrofit	Darlington	Deferred	11.379

Legend:
EAC= Estimate-At-Complete based upon latest Business Case Summary ("BCS").

APPENDIX B – AACE AND BCS CLASSIFICATIONS FOR ESTIMATES

Estimate Class

Estimate Class is a cost estimate classification system developed by the Association for the Advancement of Cost Engineering International (AACE) which defines the estimate "quality" based on the input information used and the project's stage of development. AACE uses five estimate classes with Class 5 being the least accurate, and Class 1 being the most accurate. Below is a table that is included in the instructions for Cost Estimates in the BCS template.

Estimate Class	**Class 5**	**Class 4**	**Class 3**	**Class 2**	**Class 1**
Project Phase	**Identification**	**Initiation**	**Definition**	**Execution**	**Execution**
Level of Project Definition (%)	0% to 2	1 to 15	10 to 40	30 to 75	65 to 100
Expected Accuracy Range (%)	-50 to +100	-30 to +50	-20 to +30	-15 to +20	-10 to +15

APPENDIX C – PROJECTS WITH BASELINE DISCREPANCIES

Item	Project No.	Project Description	Latest EAC (CDN$M)	Latest Target In-Service Date	CSCB Out-of-Date	CSCB Does Not Exist	Summary of Discrepancy
1	31412	DN Class II UPS Replacement	55.099M	2023-Q4	x		Vendor Schedule has not been integrated into Baseline Schedule.
2	31422	DN Pressurizer Heaters & Controllers Replacement Project	14.511M	2020-03-20	x		The current Performance Measurement Baseline (PMB) does not yet include baseline changes required by PCRAF No.'s 3 and 4 dated 15Apr2015 and 22Oct2015, respectively.
3	31508	DN Fukushima Phase 1 Beyond Design Basis Event (BDBE) Emergency Mitigation Equipment (EME)	58.391	2017-12-23	x		No Vendor Schedule. Vendor Schedule has not been integrated into Baseline Schedule.
4	40990	PN Bay Module Loader PLC Replacement	1.2M	TBD BCS under Revision		x	Integrated Cost & Schedule Control Baseline not yet established in P6 and Proliance.
5	80058	NWM Western Waste Management Facility Groundwater Monitoring Network	4.710M	2016-09-30		x	Integrated Cost & Schedule Control Baseline not yet established in P6 and Proliance.
				Totals:	**3**	**2**	

Legend:
BCS= Business Case Summary
CSCB= Cost and Schedule Control Baseline
EAC= Estimate-At-Complete
P6= OPG's Scheduling Software System.
Proliance= OPG's Cost Management Software
TBD= To be Determined

Notes:
Latest EAC and Target In-Service Date based upon latest Business Case Summary inputs.

APPENDIX D – RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgement by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

Ontario Power Generation
Internal Audits on Project Controls Audit - Project & Modifications Group
Audit Report Date: March 9, 2016

#	Finding	Management Action	Management Action Status as of March 10, 2017	Risk Rating
1	**Project estimates are not at a sufficient level of accuracy prior to the execution phase.** As per OPG's BCS requirements and the Association for the Advancement of Cost Engineering ("AACE") standards, cost estimates should be developed to at least a Class 3 estimate prior to execution (see Appendix B). For certain projects, a Class 2 estimate may be used as a "check estimate" once construction work packages are complete and just prior to the start of field execution to confirm accuracy of the Class 3 estimate submitted as part of the Execution Phase BCS. In order to come to a more precise estimate, detailed engineering must be substantially complete to determine material and labour requirements. It was noted that of the six projects sampled in the execution phase, all six projects did not have an Estimate at Completion ("EAC") for the project established at either a Class 3 or Class 2 level and they were still performing detail engineering work while in their execution phase. In some cases, the true EAC value for the entire project is not identified until the project is in the advanced stages of execution when a significant portion of the execution costs have already been incurred. (Refer to Appendix A for sample projects reviewed in the execution phase).	As part of the Nuclear Projects "Project Excellence" initiative, an estimating Centre of Excellence ("COE") is now in place within the Planning and Project Controls group; all 2016 AISC Project New Starts greater than $5 Million will require estimate review by the COE, consistent with the Gated process (See Finding 3). Gated process will also provide increased oversight in the release phase of projects and cost and estimate accuracy and contingency management.	Management completed the following to close the finding: **Closed – April 28, 2016** • Issued a series of Estimate "checking" requirements into the gated process on April 28, 2016. They include "Plan" documents for how to review Gate Packages with respect to estimates as well as a series of checklist forms which must be approved as part of gate reviews. Including requirements for approvals by centre-led Estimating Manager and solidifying the Centre of Excellence concept for estimating. **Closed – April 19, 2016** • Evidence provided showing Centre of Excellence (COE) for Estimating is in place. Gated process, when issued, will require all projects to follow Gated Process which will require a review of all estimates > $5Million by the Estimating COE. Initial focus will be on all 2016 New Starts and any projects that	High

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#	Finding	Management Action	Management Action Status as of March 10, 2017	Risk Rating
			require a Business Case to be presented to the Board. Later in 2016, the process will be expanded to all projects.	
2	**Cost and Schedule Control Baselines ("CSCB's") are not keeping pace with approved project changes.** Cost and Schedule Control Baselines ("CSCB's") are the primary control for measuring cost and schedule performance on a project. When setup correctly (i.e. Built upon reliable project estimates and front-end planning), they provide an indication of which work packages on a project are ahead or behind on cost and schedule performance, the magnitude of these variances and their net impact on the overall project. CSCB's on three out of 13 projects sampled were found not to be keeping pace with cost and schedule baseline changes being requested and approved in Business Case Summaries ("BCS's") and Project Change Request Authorization Forms ("PCRAF's"). The reliability of contractor data has contributed to this issue. This lack of accurate and timely data has contributed to Cost Performance Index ("CPI") measurements being skewed at work package levels. In addition to the above, two of the projects were found to be without CSCB's entirely. The P&M group has indicated that they are in the process of implementing project planning and control protocols with their Engineer-Procure-Construct ("EPC") vendors to ensure vendor schedules are received at the start of projects and that CSCB's are created, beginning with new	P&M is reviewing the Project Controls work processes executed by CSAs in planning and controlling projects and the amount of project work which will be executed by P&M through the Business Plan period. This information will help in determining the resource gap with CSAs. Once the gap has been determined, an appropriate resourcing strategy will be implemented. This review will include the review of BCSs and PCRAF approval processes to determine opportunities to reduce time of approval.	Management completed the following to close the finding: **Closed – September 23, 2016** Implemented the Cost and Schedule Baselines Action Plan (Dated September 22, 2016) to review the Project controls work processes executed by CSAs (const Schedule Analysis) in planning and controlling projects and the amount of project work which will be executed by P&M through the Business Plan period. This information will be issued to assess the resource gap with CSAs. Once the gap has been assessed a resourcing strategy will be implemented. The review also included the BCS and PCRAF approval process to determine opportunities to reduce time of approval which relates to approvals for implementing Cost and Schedule baselines and approved changes	Moderate

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#	Finding	Management Action	Management Action Status as of March 10, 2017	Risk Rating
	project starts for 2016.		to baselines. The review was conducted in three areas: a) P&M Work Program based on the business plan b) Simplify it - by reviewing the PCRAF and BCS processes to identify low or no valve activities which can reduce the work burden on the CSA and project team. c) Gated Process Review for Readiness to process	
3	**A Gating Process for AISC Portfolio Projects has not been formally implemented.** A gating process is meant to define a clear list of requirements, deliverables, and expectations a project should follow in order to be granted approval to proceed to its next phase within the typical five phases of a project's life cycle. In addition to the above, a robust gating process also requires that a project be defined and associated work scope be estimated to specified levels of accuracy. Although the AISC acts as a de facto Gate Review Board for AISC projects, the gating process outlined in the Nuclear Projects governance (N-STD-AS-0028) and Project Management Manual (N-MAN-00120-10001-GRB) has not been fully implemented for AISC projects. At present, the primary control used for gate approval between phases in the AISC project life cycle is the BCS process. While this is an important	The Nuclear Projects Gated process will become the standard approach for P&M AISC projects beginning with 2016 Project New Starts. This change has been approved by the SVP/CNE and VP, P&M and an initiative is underway to align and implement the Gated process. Finance will be involved in the gate review process. Implementation requires the following actions: 1. Establish a common Gated process for all Nuclear Projects. 2. Through a Change Management Plan, prepare and issue desktop guides for Project Life Cycle to AISC	Management completed the following to close the finding: **Closed – April 19, 2016** 1. Management has developed a common Gated process for Nuclear Projects. An update to N-STD-AS-0028 reflecting the new common Gated process will was issued on April 28. 2. N-MAN-00120-10001-GRB and the associated forms/check sheets have been updated and issued on April 29 in governance. A change management presentation summarizing the changes was	Moderate

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#	Finding	Management Action	Management Action Status as of March 10, 2017	Risk Rating
	requirement, the BCS process does not constitute a complete list of all the deliverables required at each gate approval, nor formalize the challenge process that should take place regarding the approval of each deliverable. Management has indicated that they are in the process of formalizing a gating process for AISC projects in Q1 2016.	Members and Project Managers. 3. Preparation and Issuance of AISC Terms of Reference to AISC Members and Project Managers.	developed and presented at an AISC meeting in Q2 2016. **Closed – April 26, 2016** 3. AISC Terms of Reference guideline – N-GUID-00120-10016– Dated April 19, 2016.	
4	**Governance and Procedures specific to AISC projects require improvement.** There are three key gaps identified in governance and procedures that should be addressed: 1. A formal Terms of Reference ("TOR") document does not exist to govern the role, accountabilities, and operation of the AISC; 2. Although Nuclear Projects Governance should apply to AISC funded projects, this principal is not adequately documented as AISC projects follow existing Finance governance. To reduce this confusion, some AISC specific processes should be defined including: a. The scope and change management process involving PCRAF's should be substituted with the current process in Nuclear projects called CCF; b. The gating process, including the requirements and deliverables for each gate; and c. The process for establishing and integrating vendor schedules, establishing forecast inputs,	Recommendations 1 and 2: Action plan for Finding 3 will include issuance of AISC Terms of Reference and a desktop guide to assist projects under AISC authority in the use of Nuclear Projects Governance, specifically the gated process**.** Recommendations 3: Nuclear Projects is in the process of developing standardized reports using Ecosys. Phase 1 implementation will be in Nuclear Refurbishment and Phase 2 will be in P&M.	Management completed the following to close the finding: **Closed – April 26, 2016** • Recommendations 1 and 2 of Finding No. 4 were closed under Finding No.3. Project Controls provided AISC Terms of Reference and revised Nuclear Gating Process on the associated due date. • Recommendation 3: Rollout to P&M for P&M projects in Ecosys was scheduled to be completed by Dec 2016, whereas rollout for AISC projects in Ecosys was to be completed in Q1 2017. IA accepted evidence consisting of 28 active P&M project reports available in Ecosys as of Dec 13,	Low

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#	Finding	Management Action	Management Action Status as of March 10, 2017	Risk Rating
	work breakdown structure requirements, etc. 3. Requirements for month-end performance reports and record keeping are undefined. Each project manager runs their project using a different set of month-end reports and reports are not formally stored by project in a central directory for future reference.		2016 (evidence: list and samples), together with evidence that AISC projects in Ecosys were to be rolled out in Q1 2017 and were tracked via RMO action #6602. P&M reports were considered a standardized template for both P&M and AISC projects. Thus "Standardize reporting for AISC projects" is done. IA Confirmed that all of P&M data are loaded. It consists of P&M's non NR projects and totals over 100 projects. • Supplementary evidence provided showing that gated process has been implemented. P&M provided the list of AISC 2016 "New Starts" projects indicating that respective Gate Packages has been filed.	

UNDERTAKING J7.4

Undertaking

To provide the threshold number for all projects that triggers approval of over-variance expenditures

Response

Approval is required for all projects where a variance is expected from the original budget (i.e., the business case release amount). These variances require approval at the same organizational authority level as the original business case or a higher level, depending on the revised total project cost. During final project closeout, a minor variance related to costs incurred does not require a Project Over-Variance Approval form.

UNDERTAKING J7.5

Undertaking

With reference to each item listed in JT3.22, advise whether the values in the column entitled “budget” are the original budgeted amounts or if they have been adjusted.

Response

With the exception of the two projects identified below, the values in the Budget column in JT3.22 represent the original budgets for the other 13 projects listed. The original budgeted amounts (Initial Full Release) for these two projects are shown in the “Original Budget” column below.

Project Title	PIR Approval Date	Original Budget ($M)	Budget ($M)	Actual Cost ($M)
Radiation Shielding Structure	26-Nov-15	3.3	4.0	4.0
PA EQ Containment Damper Deficiency - Installation of New Maintenance Dampers	18-Oct-16	0.8	1.5	1.4

UNDERTAKING J8.1

Undertaking

PROVIDE A NUCLEAR MATERIALITY CALCULATION ON THE SAME BASIS AS EX. L-11.1-CCC-047

Response

The charts below provide the materiality calculations from Ex. L-11.1-CCC-047 using nuclear input values.

Average Annual Rate Base ($M)	Materiality Threshold %	Materiality Threshold ($M)
$3,496.5*	0.25%	$8.7

*(EB-2007-0905 Payment Amounts Order, Appendix A, Table 2)

	Note	Formula Value ($M)	Materiality Threshold %	Materiality Threshold ($M)
Revenue Requirement	1	$3,360.3	0.50%	$16.8
Rate Base	2	$4,834.0	0.25%	$12.1
Average Threshold Value				$14.4

Note 1: Ex. N2-1-1 Table 1, Line 28. Annual average of total for 2017 to 2021, applying the same 0.5% value used to determine materiality for electricity distributors based on their revenue requirements.

Note 2: Ex. N2-1-1 Table 1, line 4 ($5,210.4M) less Ex. N2-1-1, Table 1, line 8 ($376.4M). Values are the averages over the five year period of 2017 to 2021.

UNDERTAKING J8.2

Undertaking

Clarify the Z-factor materiality threshold under the nuclear Custom IR application

Response

Nuclear Materiality Threshold

OPG proposes that a $10M regulatory materiality threshold would apply to an application to address the financial impact of unforeseen events related to the nuclear business.

This is the same materiality threshold that OPG has proposed and applied in prior proceedings, and used to prepare the Impact Statements filed in this application. In past proceedings, a $10M materiality threshold has been used to determine whether an accounting order application is required[1] and whether OPG is required to file an update to comply with section 11.02 of the OEB's Rules of Practice and Procedure.[2]

OPG believes that $10M remains an appropriate regulatory materiality threshold. OPG notes that the OEB has capped the range of materiality thresholds for electricity distributors at $1M, even for distributors with large rate bases and revenue requirements.[3]

Treatment of Unforeseen Events under Nuclear Custom IR

OPG has not specifically proposed the mechanism by which the financial impacts of unforeseen events related to the nuclear business should be dispositioned, only that such events be addressed pursuant to the *Renewed Regulatory Framework for Electricity Distributors.*[4]

A Z-factor is only one method by which the OEB may address the financial impact of unforeseen events under a Custom IR framework.

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[1] EB-2012-0002, Payment Amounts Order, April 18, 2013, page 7; EB-2013-0321, Decision with Reasons, November 20, 2014, page 127.
[2] E.g., EB-2013-0321, Ex. N2-1-1, page 1, line 16.
[3] *Filing Requirements for Electricity Distribution Rate Applications* (July 14, 2016), Chapter 2, page 6, section 2.0.8.
[4] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), page 13; Transcript Volume 8, March 10, 2017, page 23, lines 19-28.

OPG has previously addressed the financial impact of material unforeseen events through an accounting order process. OPG has applied for accounting orders three times since the OEB first established payment amounts for the company:

1. **EB-2009-0174:** An administrative proceeding.
2. **EB-2011-0432:** An application that addressed OPG's transition to US GAAP as part of the industry-wide adoption of new accounting methodologies. The application resulted in approximately $60M being recovered from customers.
3. **EB-2015-0374:** An application filed pursuant to OEB direction, reflecting a change in the end-of-life for nuclear facilities. The application will result in approximately $70M being refunded to customers.

In OPG's submission, accounting orders remain an appropriate mechanism by which to address the financial impact of unforeseen events that may affect the nuclear business during the 2017-2021 period.

Continued use of accounting orders to address unforeseen events would also be consistent with the Payment Amounts Order of the OEB in EB-2012-0002, in which the OEB directed that:

> OPG **shall file an accounting order application**… if, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, OPG proposes to effect an accounting change impacting the calculation of its Nuclear Liabilities that results in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes). **OPG shall not be required to apply for such accounting orders if the impact on the annualized revenue requirement impact for the prescribed facilities is less than $10M.** [Emphasis added]

The Payment Amounts Order in EB-2013-0321 included a similar direction.[5] OPG notes that the OEB applied a $10M materiality threshold to both directions, consistent with the threshold proposed by OPG in this application.

[5] EB-2013-0321, Payment Amounts Order, page 9, item 14.

UNDERTAKING J8.3

Undertaking

What is the revenue requirement for 2020 and 2021 specific to Unit 2 contingency costs.

Response

The revenue requirement specific to expending and placing in service the Darlington Unit 2 contingency of $694.1M is approximately $56M in 2020 and $67M in 2021. Additionally, there are credits to ratepayers of approximately $2M in 2018 and $12M in 2019 reflected in the proposed revenue requirement on account of contingency expenditures, related to capital cost allowance tax deductions.[1]

These estimated amounts were derived in the manner shown in L-4.3-2 AMPCO-077.

[1] The incremental revenue requirement impact of these credits is partly reflected in the 2017 proposed revenue requirement through the effect of carrying back projected 2018 and 2019 regulatory tax losses to 2017, as noted in Ex. N2-1-1, p. 3, lines 11-17.

UNDERTAKING J8.4

Undertaking

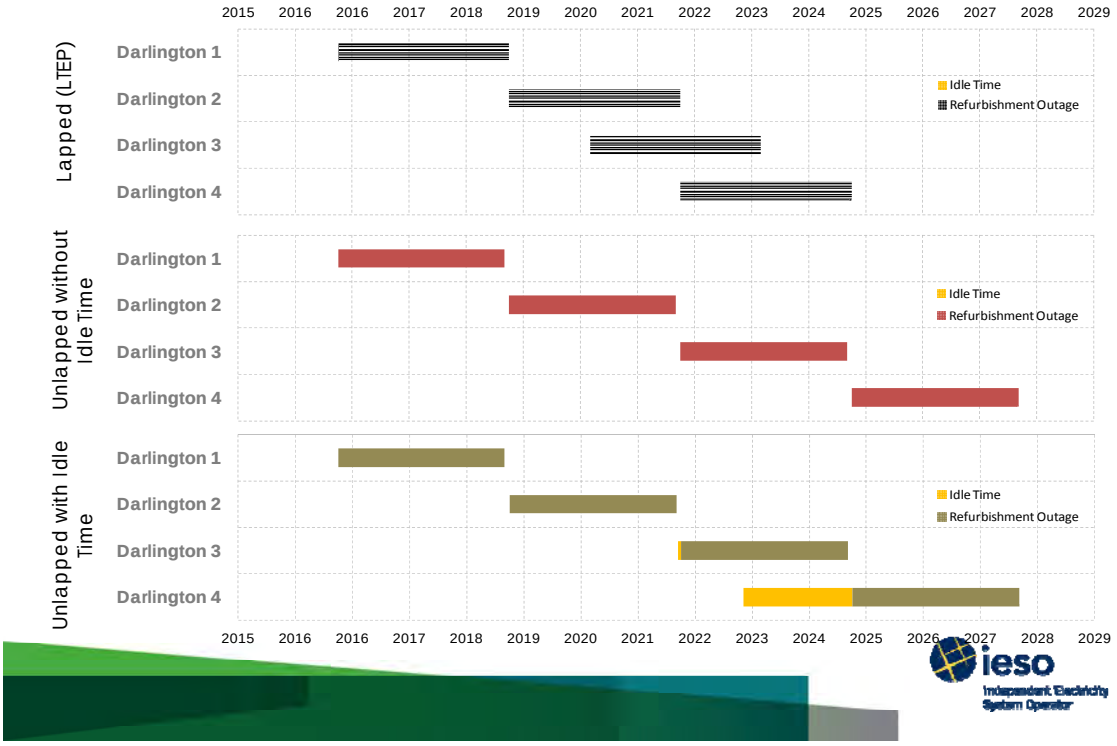
To advise whether the change in the DRP schedule, whereby Units 2 and 3 have been unlapped, has been accounted for in the IESO's analysis.

Response

The March 2015 study considered Darlington refurbishment schedules that were unlapped (refurbishment outages not overlapping) and lapped (refurbishment outages overlapping) (Figure 1). The October 2015 study considered the lapped refurbishment schedule.

Figure 1: Darlington Refurbishment Schedules March 2015 study.

Pickering extension options were assessed against three Darlington refurbishment sequences. One sequence features some overlap among Darlington refurbishments. Two sequences feature no overlap - in sequences without overlap, one relies on idle time at Darlington units 3 and 4 to attain the required service life.



UNDERTAKING J8.5

Undertaking

To confirm that the Nymex future prices (see also Ex. K8.1, p.2, footnote 3), and the IESO Price Premium numbers in the chart found at Ex. K8.1, p.2 are accurate.

Response

Ex. K8.1, p.2 presented the following table:

	2017	2018	2019	2020	2021	2022	2023	2024
IESO Forecast (2015 real U.S. $/MMBTU)	5.45	5.45	5.44	5.44	5.43	5.43	5.43	5.43
IESO Forecast (nominal U.S. $/MMBTU)	5.67	5.78	5.89	6.01	6.12	6.24	6.36	6.49
NYMEX Future Prices ($/MMBtu)	3.35	3.05	2.99	3.02	3.01	3.03	3.08	3.16
IESO Price Premium	69%	90%	97%	99%	103%	106%	106%	105%

[1] Ex. L, Tab 6.5, Sch. 7 ED-028, Page 5
[2] Conversion from 2015 real $ based on assumed 2% annual inflation rate.
[3] As of March 6, 2017: http:www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

The specific NYMEX Future Prices presented in the table above cannot be confirmed as those instantaneous quotes no longer exist on the website cited. However, a comparison of the futures prices available on the website as of March 13, 2017 to those in the table above indicates there has not been a significant deviation in gas futures prices over the previous seven days (see table below).

NYMEX Future Prices ($USD/MMbtu)	2017	2018	2019	2020	2021	2022	2023	2024
March 6, 2017 (Tab 2)	3.35	3.05	2.99	3.02	3.01	3.03	3.08	3.16
March 13, 2017	3.37	3.07	2.99	2.99	3.00	3.01	3.04	3.11

The percentage by which the IESO nominal forecast exceeds the NYMEX future price illustrated in the table at Ex. K8.1, p.2 appears to be calculated correctly using the March 6, 2017 NYMEX future prices.

UNDERTAKING J8.6

Undertaking

To advise on the differential that was assumed in the analysis between Henry Hub and Dawn amounts.

Response

The following table summarizes the price differential between Dawn Hub and Henry Hub assumed in the analysis, consistent with the publicly available natural gas forecast used. Note that the basis differential used is positive, indicating that the Dawn price is more expensive than Henry Hub.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2016	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2017	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2018	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2019	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2020	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2021	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2022	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2023	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2024	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2025	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2026	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2027	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2028	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2029	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2030	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2031	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27
2032	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.26	0.25	0.26	0.26	0.27

Source: Sproule.

UNDERTAKING J8.7

Undertaking

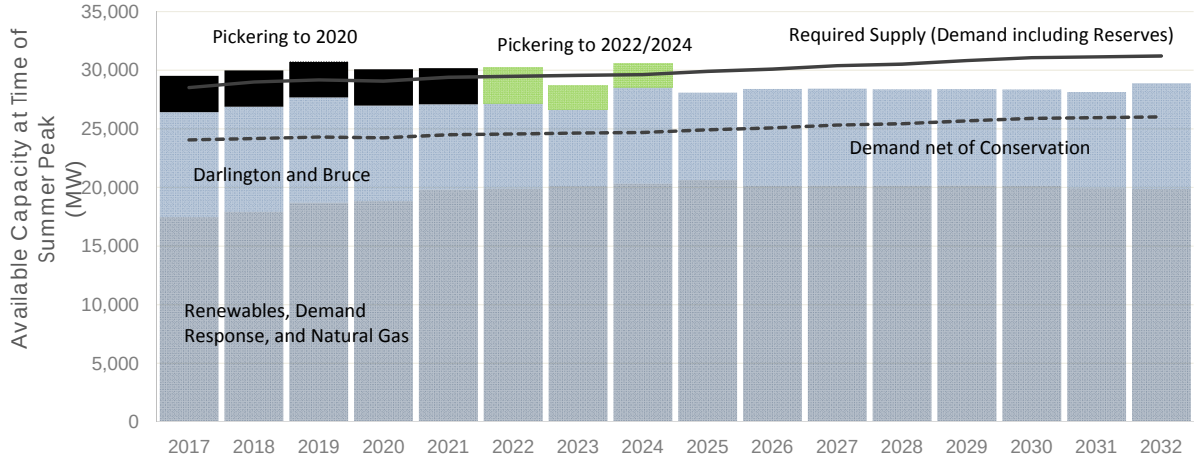
Reference: Ex. F2-2-3, Att. 1, p. 5

To provide a table comparing the resource requirement line found at Ex. F2-2-3, Att. 1, p. 5 with the latest version of the resource requirement line.

Response

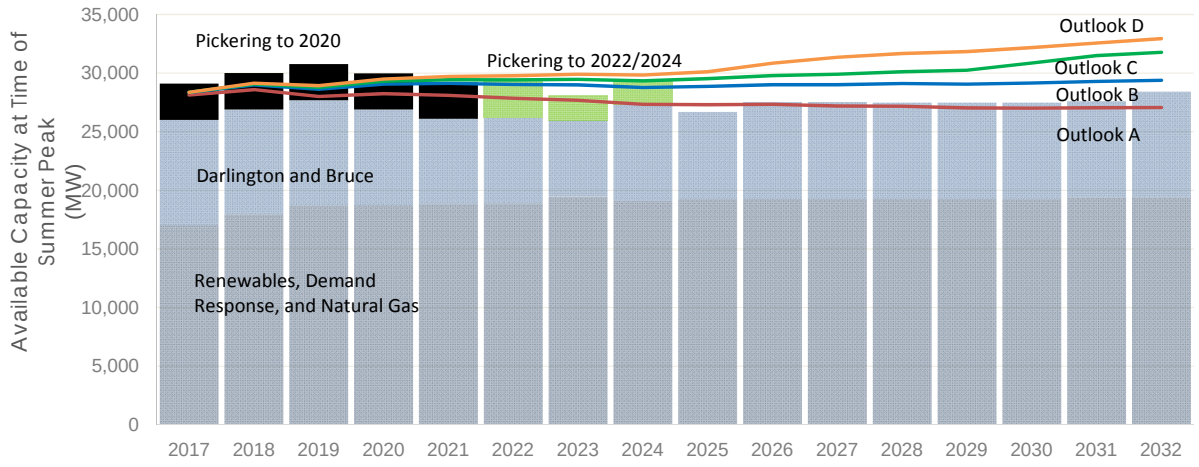
The available resources at time of summer peak and the required supply are shown in Figures 1 and 2, for the October 2015 Pickering Assessment and an indicative March 2017 outlook respectively. Note the IESO is currently in the midst of updating its planning outlook and an indicative outlook based on current information is illustrated herein.

Figure 1: Available Resources at Time of Peak – October 2015 Pickering Assessment[1]



[1] Demand outlooks are consistent with the Ontario Planning Outlook (2016). http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Figure 2: Available Resources at Time of Peak – March 2017 Outlook*



The resource above requirement for the October 2015 Pickering Assessment and the updated March 2017 outlook is shown in Tables 1 and 2. The resource above requirement is the difference between the available resources and required supply. While the March 2017 Outlook is still a work in progress, it is considered indicative.

Table 1: Summer Resource Above Requirement – October 2015 Pickering Assessment

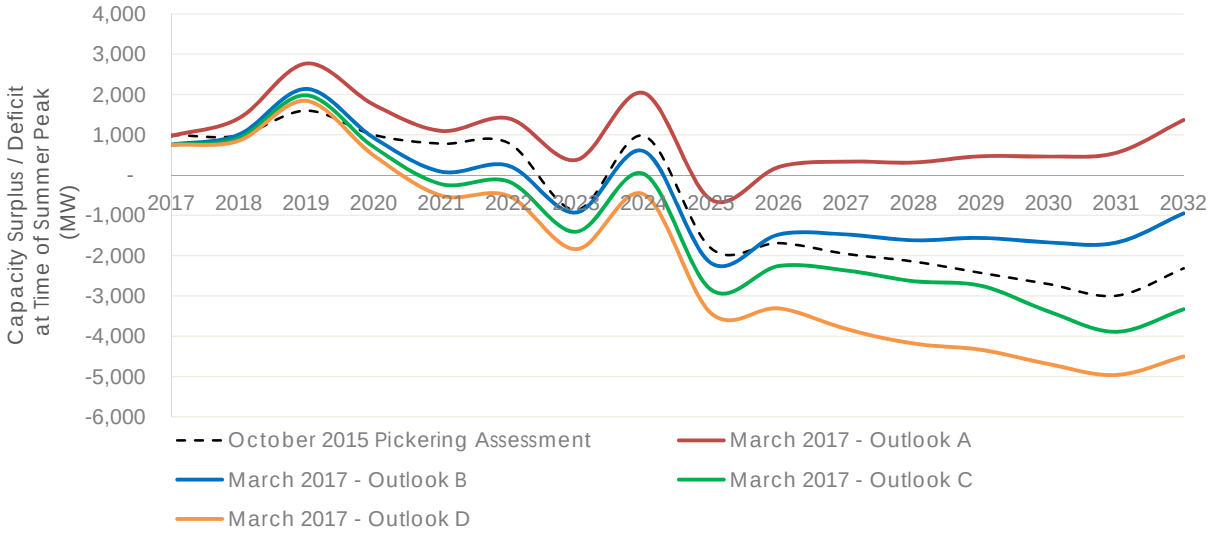
MW	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Available Resources	29,519	29,971	30,760	30,073	30,177	30,266	28,696	30,592
Required Supply	28,521	28,990	29,161	29,076	29,398	29,473	29,563	29,619
Resource Above Requirement	998	981	1,599	997	778	793	-867	974
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Available Resources	28,073	28,402	28,422	28,364	28,384	28,357	28,141	28,897
Required Supply	29,895	30,091	30,378	30,511	30,813	31,063	31,134	31,213
Resource Above Requirement	-1,822	-1,688	-1,956	-2,146	-2,429	-2,706	-2,994	-2,315

Table 2: Summer Resource Above Requirement – March 2017 Outlook

	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Available Resources	29,099	29,992	30,759	29,983	29,196	29,255	28,053	29,362
Required Supply								
Outlook A	28,128	28,583	27,990	28,236	28,100	27,848	27,678	27,325
Outlook B	28,343	28,988	28,620	29,058	29,111	29,024	28,981	28,768
Outlook C	28,350	29,069	28,777	29,288	29,422	29,416	29,459	29,332
Outlook D	28,350	29,139	28,917	29,498	29,705	29,773	29,891	29,838
Resource Above Requirement								
Outlook A	971	1,408	2,769	1,747	1,097	1,407	375	2,037
Outlook B	756	1,004	2,139	925	85	231	-929	595
Outlook C	749	922	1,982	695	-225	-161	-1,407	30
Outlook D	749	852	1,842	485	-509	-519	-1,839	-476
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Available Resources	26,677	27,527	27,526	27,481	27,485	27,472	27,596	28,429
Required Supply								
Outlook A	27,291	27,326	27,192	27,169	27,016	27,011	27,044	27,060
Outlook B	28,863	29,001	29,001	29,100	29,044	29,142	29,273	29,377
Outlook C	29,525	29,783	29,894	30,114	30,233	30,858	31,485	31,758
Outlook D	30,109	30,835	31,347	31,664	31,822	32,163	32,558	32,930
Resource Above Requirement								
Outlook A	-615	201	334	312	470	462	552	1,369
Outlook B	-2,187	-1,475	-1,475	-1,619	-1,559	-1,670	-1,677	-948
Outlook C	-2,848	-2,257	-2,368	-2,634	-2,748	-3,386	-3,890	-3,329
Outlook D	-3,433	-3,308	-3,821	-4,184	-4,336	-4,690	-4,963	-4,501

Figure 3 illustrates the summer resources above requirement (capacity surplus/deficit) for the two outlooks (Pickering to 2022/2024).

Figure 3: Comparison of Resource Above Requirement – October 2015 Pickering Assessment and March 2017 Outlook (Pickering to 2022/2024)



Although resource requirements illustrated above are at the time of summer peak, note that in Outlooks C and D Ontario transitions to a winter peaking system over the planning horizon.

UNDERTAKING J8.8

Undertaking

To advise on the expiry date of the three NUG contracts representing about 270 MW of capacity, in particular, if any of these contracts expire in 2021, 2022, or 2023.

Response

The NUG contracts representing the 270 MW of installed capacity and their contract expiry dates are as follows:

- Iroquois Falls - 126 MW (January 1, 2022)
- Nipigon – 40 MW (December 31, 2022)
- Kirkland Lake (base load) – 103 MW (August 23, 2031)

UNDERTAKING J8.9

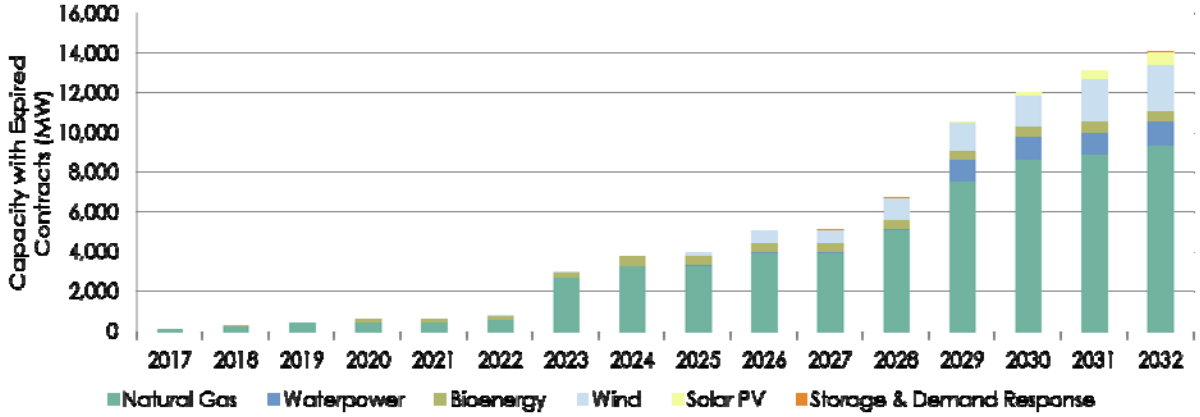
Undertaking

To confirm the number of NUG contracts assumed to be renewed in the analysis.

Response

The analysis considered that some of the capacity currently under contract would remain in-service following contract expiry. The amount of capacity expiring over the planning period of the Pickering study is illustrated in Figure 1.

Figure 1: Capacity with Expired Contracts



Approximately 4,000 MW of capacity currently under contract reaches the end of its contract term by 2024. In the analysis, most of this capacity was assumed to continue to remain in operation.

Regarding NUG capacity in particular, 397 MW of NUG capacity was estimated to reach the end of contract term by 2024. Approximately 269 MW of this capacity was assumed to remain in service, while 128 MW was not assumed to remain in-service.

UNDERTAKING J8.10

Undertaking

Reference: Ex. K8.1, Tab 10, p. 21

To break down the capacity requirement assumptions between summer and winter.

Response

For the case with Pickering to 2020, the figures below illustrate the summer and winter capacity requirements in the October 2015 Pickering assessment and an indicative March 2017 outlook. Note the IESO is currently in the midst of updating its planning outlook and an indicative outlook based on current information is illustrated herein.

Figure 1: Comparison of Summer Capacity Requirements – October 2015 Pickering Assessment and March 2017 Outlook (Pickering to 2020)[1]

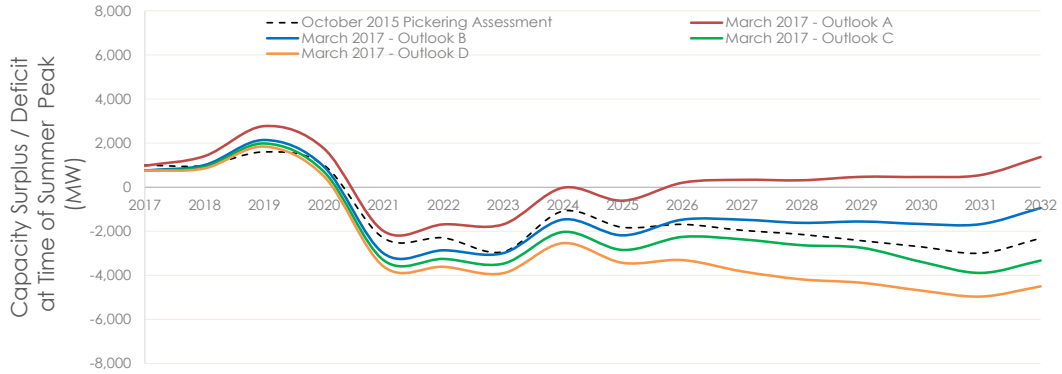
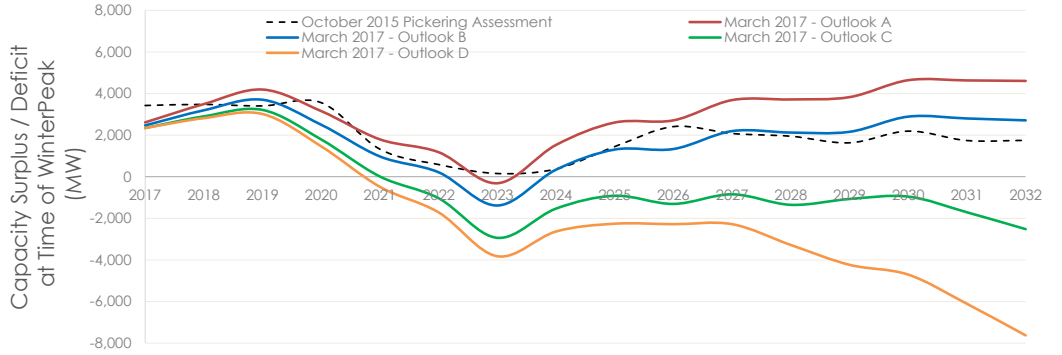


Figure 2: Comparison of Winter Capacity Requirements – October 2015 Pickering Assessment and March 2017 Outlook (Pickering to 2020)



[1] Note that demand outlooks are consistent with the Ontario Planning Outlook (2016). http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Table 1: Comparison of Summer Capacity Requirements – October 2015 Pickering Assessment and March 2017 Outlook (Pickering to 2020)

Resource Above Requirement (MW)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
October 2015 Pickering Study	998	981	1,599	997	-2,316	-2,301	-2,931	-1,090
March 2017, Outlook A	971	1,408	2,769	1,747	-1,997	-1,687	-1,689	-27
March 2017, Outlook B	756	1,004	2,139	925	-3,009	-2,863	-2,993	-1,469
March 2017, Outlook C	749	922	1,982	695	-3,319	-3,255	-3,471	-2,034
March 2017, Outlook D	749	852	1,842	485	-3,603	-3,613	-3,903	-2,540
Resource Above Requirement (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
October 2015 Pickering Study	-1,822	-1,688	-1,956	-2,146	-2,429	-2,706	-2,994	-2,315
March 2017, Outlook A	-615	201	334	312	470	462	552	1,369
March 2017, Outlook B	-2,187	-1,475	-1,475	-1,619	-1,559	-1,670	-1,677	-948
March 2017, Outlook C	-2,848	-2,257	-2,368	-2,634	-2,748	-3,386	-3,890	-3,329
March 2017, Outlook D	-3,433	-3,308	-3,821	-4,184	-4,336	-4,690	-4,963	-4,501

Table 2: Comparison of Winter Capacity Requirements – October 2015 Pickering Assessment and March 2017 Outlook (Pickering to 2020)

Resource Above Requirement (MW)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
October 2015 Pickering Study	3,426	3,480	3,407	3,562	1,326	586	155	374
March 2017, Outlook A	2,615	3,493	4,194	3,157	1,797	1,180	-312	1,531
March 2017, Outlook B	2,469	3,196	3,703	2,500	975	214	-1,382	339
March 2017, Outlook C	2,343	2,903	3,214	1,793	10	-1,033	-2,938	-1,532
March 2017, Outlook D	2,343	2,818	3,018	1,462	-486	-1,714	-3,823	-2,633
Resource Above Requirement (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
October 2015 Pickering Study	1,450	2,412	2,079	1,948	1,632	2,194	1,741	1,750
March 2017, Outlook A	2,608	2,713	3,688	3,717	3,829	4,643	4,632	4,608

March 2017, Outlook B	1,309	1,334	2,196	2,125	2,161	2,892	2,803	2,712
March 2017, Outlook C	-915	-1,307	-845	-1,350	-1,069	-954	-1,709	-2,518
March 2017, Outlook D	-2,258	-2,281	-2,281	-3,281	-4,234	-4,707	-6,109	-7,629

The increase in the capacity requirements during the summer and winter periods between operating Pickering to 2020 relative to 2022/2024 are indicated below.

Table 3: Increase in Summer Capacity Requirements between Pickering to 2020 relative to 2022/2024

(MW)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
October 2015 Pickering Study	-	-	-	-	2,316	2,301	2,064	1,090
March 2017, Outlook A	-	-	-	-	1,997	1,687	1,689	27
March 2017, Outlook B	-	-	-	-	3,009	2,863	2,064	1,469
March 2017, Outlook C	-	-	-	-	3,094	3,094	2,064	2,034
March 2017, Outlook D	-	-	-	-	3,094	3,094	2,064	2,064

Table 4: Increase in Winter Capacity Requirements between Pickering to 2020 relative to 2022/2024

(MW)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
October 2015 Pickering Study	-	-	-	-	-	-	-	-
March 2017, Outlook A	-	-	-	-	-	-	312	-
March 2017, Outlook B	-	-	-	-	-	-	1,382	-
March 2017, Outlook C	-	-	-	-	-	1,033	2,064	1,532
March 2017, Outlook D	-	-	-	-	486	1,714	2,064	2,064

UNDERTAKING J9.1

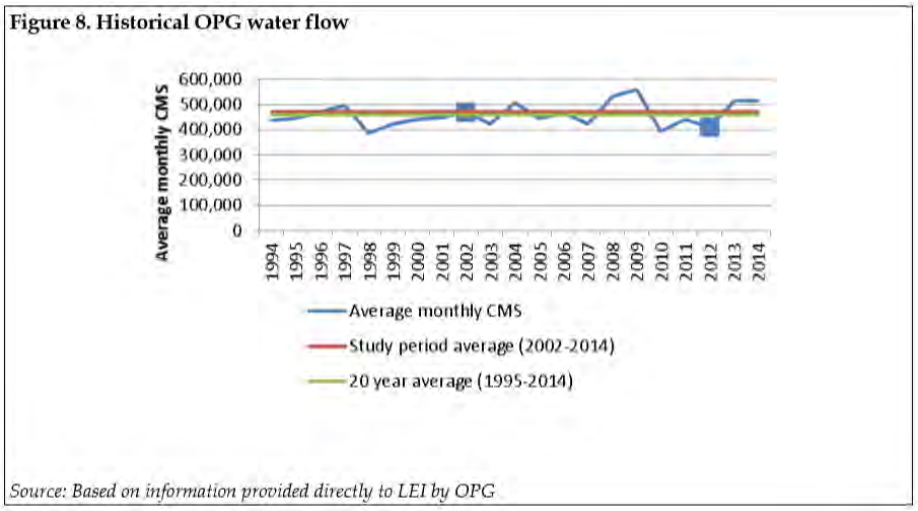
Undertaking

To provide trend line for average water flows over the 2002-2014 period.

Response

The following response was provided by LEI.

Figure 8 of LEI's 2016 TFP Study (page 18) compares 2002-2014 average annual water flow level to the longer-term level (20-year average) from 1994-2014.



As shown in Figure 8, OPG's average water flows during the study period of 2002-2014 were within 1%-difference of the twenty-year average (1994-2014).

The actual MWh of electricity generated by OPG and the Output Index values and annual rates of change for OPG's regulated hydroelectric generation over the study timeframe were presented in LEI's work papers, which was filed as "Attachment 1: Model A: OPG industry TFP model v2016 final.xlsx" in OPG's response to Board Staff Interrogatory #246 (EB-2016-0152, Exhibit L, Tab 11.1, Schedule 1, Staff-246, filed 2016-10-26).

The requested information on OPG's trends are documented in Figure 1 below. The OPG-specific net generation (MWh)-based output index had an average trend of -0.87% over the study period of 2002-2014. In comparison, over the same study period of 2002-

2014, LEI's hydroelectric industry composite had an average output index trend of -0.64% (based on Figure 27 of LEI's 2016 TFP Study, page 42).

Figure 1. OPG-specific input, output and TFP index growth rates using the average growth method

	Quantity Sub-indexes Growth rates		
Year	Input Index Growth	Output Index Growth	TFP Index Growth
2002-2003	0.86%	-2.31%	-3.17%
2003-2004	0.35%	6.27%	5.92%
2004-2005	-0.13%	-5.42%	-5.28%
2005-2006	1.33%	2.48%	1.15%
2006-2007	0.22%	-3.99%	-4.21%
2007-2008	1.47%	12.62%	11.15%
2008-2009	-1.38%	-3.04%	-1.66%
2009-2010	-0.45%	-17.19%	-16.75%
2010-2011	-7.27%	-0.68%	6.59%
2011-2012	0.09%	-6.47%	-6.55%
2012-2013	0.29%	6.42%	6.13%
2013-2014	0.14%	0.91%	0.77%
AVERAGE	**-0.37%**	**-0.87%**	**-0.49%**

Source: Attachment 1: Model A: OPG industry TFP model v2016 final, provided by LEI for OPG's response to Board Staff Interrogatory #246 (EB-2016-0152, Exhibit L, Tab 11.1, Schedule 1, Staff-246, filed 2016-10-26).

UNDERTAKING J9.2

Undertaking

TO RECONCILE 2013 ACTUAL RESULTS AND THE NUMBERS USED BY NAVIGANT, AS PRESENTED BY OEB STAFF ON PAGE 30 OF EXHIBIT K9.1

Response

In this response, OPG provides two reconciliations between the total cost benchmarked and the 2013 actual values of regulated hydroelectric costs as reported in EB-2013-0321:

1. Total Regulated Hydroelectric Cost to Navigant's Partial Function Cost, and
2. Regulated Hydroelectric OM&A to Navigant's Partial Function Cost.

Total Regulated Hydroelectric Cost to Partial Function Cost

The first reconciliation starts with total 2013 actual hydroelectric costs (line 3) and adjusts for differences in the treatment of capital related costs in Navigant's study (lines 4 to 8), arriving at the total costs benchmarked by Navigant (line 9). It then adjusts for regional wage differences (line 10) and removes the investment function and PA&R functions (lines 11 and 12) to derive the Partial Function Cost value used to benchmark OPG against its peers (line 13).

Regulated Hydroelectric OM&A to Partial Function Cost

The second reconciliation starts with the 2013 actual hydroelectric OM&A costs (line 16), from which it removes costs that are not benchmarked by Navigant (line 19), adjusts for regional wage differences (line 20), removes costs that Navigant does not include in the partial function cost benchmark metric (lines 21 to 26), and identifies methodological differences that apply to determining the labour component of OM&A costs that are not derived using accrual accounting (line 27). The result is the same Partial Function Cost value identified in the first reconciliation.

RECONCILING TOTAL COST TO PARTIAL FUNCTION COST

Line	Amount	Description
1	454.7	Total Cost PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15, line 12)
2	331.3	Total Cost NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16, line 12)
3	**786.0**	Line 1 +2
		Deduct Accrual Accounting Asset-Related Costs (Depreciation, Amortization, Taxes)
4	(80.6)	Total Asset Related Costs PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15, line 8 to 11)
5	(59.2)	Total Asset Related Costs NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16, line 8 to 11)
6	87.2	Add back: 2013 Actual Capital Asset-related expenditures (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 8, lines 3 and 9)
7	(59.3)	OM&A Costs not benchmarked (EB-2016-0152, Ex A1-3-2, Attachment 2, page 5
8	(1.8)	Correction for administrative error identified by OEB Staff (Ex. K9.1, page 30, line 6). The dollar value of the "Total Costs Not Benchmarked" reported on page 5 of Navigant's study (Ex. A1-3-2, Attachment 2) were understated by $1.8M. The percentage of total costs benchmarked was reported accurately at 91.7%.
9	**672.3**	Total Costs Benchmarked (sum of lines 3 through 8, and per EB-2016-0152, Ex A1-3-2, Appendix 2, page 5)
10	666	Line 9 Benchmarked Cost Adjustment for regional wages (EB-2016-0152 Ex A1-3-2, Attachment 2, page 5)
11	326	Public Affairs and Regulatory Cost Benchmark Function
12	140	Investment Cost Benchmark Function
13	**201**	Partial Function Cost Benchmark (Line 10 less lines 11 and 12 - difference due to rounding)

RECONCILING TOTAL OM&A TO PARTIAL FUNCTION COST

Line	Amount	Description
14	124.7	Total OM&A PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15, line 6)
15	196.6	Total OM&A NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16, line 6)
16	**321.3**	Lines 14 + 15
17	(59.3)	OM&A Costs not benchmarked (EB-2016-0152, Ex A1-3-2, Attachment 2, page 5)
18	(1.8)	Correction for administrative error as described in line 8 above
19	**260.2**	Sum of lines 16, 17 and 18
20	**257.8**	Adjust Line 19 by 666/672.3 regional wage difference
		Deduct OM&A Costs Not Directly Included In Partial Function Cost
21	14.7	Project OM&A PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15, line 2)
22	23.1	Project OM&A NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16, line 2)
		Deduct Engineering and Support OM&A costs allocated to Investment and PAR benchmark functions
23	7.7	Engineering cost benchmarked under the Investment Function
24	3.7	Other support cost (project overhead) are reported as OM&A but for benchmarking Navigant considers these cost to be Investment
25	1.4	Base OM&A engineering and support costs included in PA&R
		Deduct Nippissing OM&A
26	0.2	Nippissing GS Closure: Navigant used OM&A costs associated with operating stations. OPG is incurring cost to maintain the dam and station.
		Methodology Differences
27	6.0	Navigant determines labour costs through a detailed bottom up methodology that starts with FTEs in each job and then builds up labour costs by multiplying FTEs by average hourly wages, hours/year, and a forecast benefits multiplier, to arrive at a representative and comparable total. Overtime, contractor, and non-labour costs are added to the straight time labour totals. This bottom up approach normalizes for variability that results from staff turnover timing and enhances comparability of performance among peers but introduces sources of minor variances compared to OM&A accrual based accounting costs. For example, Navigant uses the forecast labour burden for benefits, while reported OM&A will reflect actual benefits and costs. Navigant also amended its approach to applying the labour burden to overtime costs that results in a minor variance to reported OM&A.
28	**201.0**	Subtract lines 21 through 27 from line 20

UNDERTAKING J10.1

Undertaking

To provide reference to evidence where LEI's working papers are provided.

Response

Please see Tr. Vol. 10, p. 54, lines 22-23.

UNDERTAKING J10.2

Undertaking

LEI to provide summary statistic progression results, including T-statistic, R-squared and confidence level.

Response

Reference:
Ref: Exhibit L, Tab 11.1 Schedule 1 Staff-246

LEI performed a regression analysis to analyze whether a linear relationship exists between the industry average TFP growth rates and time. The following time series table is contained in LEI's work papers and was used to perform the TFP trend regression calculation.

T *(X variable)*	Natural log of TFP index values *(Y variable)*
0	0.00
1	0.07
2	0.03
3	0.04
4	0.06
5	-0.11
6	-0.08
7	0.02
8	-0.04
9	0.04
10	-0.11
11	-0.09
12	-0.12

As outlined in Figure 6 on page 15 in LEI's 2016 TFP Study (which is reproduced below), the equation was formulated to regress the annual industry TFP growth rates, in the form of natural logarithm of the TFP index values (the Y variable), against the number of years of the study period (the X variable). This trend regression approach is commonly used in business, finance and economics to explore the change in the Y variable over time.[1] The estimated coefficient on the X variable (number of years) is then the average TFP growth rate over the period being examined. As noted in Section 6.2.2 of LEI's report, the purpose of the trend regression method was to confirm, by another technique, the annual average TFP growth rate over the study timeframe produced by the average growth method.

Figure 6. Trend regression of TFP growth for a study period of 2002-2014

$$\text{Regress: } \ln(\text{industry TFP index}) = \beta * T + \alpha$$

Where:
β = trend growth rate for the industry TFP index over the study period
T = time in years $(0, \ldots, 12)$
α = constant term

The summary statistical outputs for the above equation are found in the tables below:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.645446573
R Square	0.416601278
Adjusted R Square	0.363565031
Standard Error	0.056587484
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.02515293	0.02515293	7.855029306	0.017192078
Residual	11	0.035223577	0.003202143		
Total	12	0.060376507			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.047100291	0.029659901	1.588012423	0.140590785	-0.018180711	0.112381292
T (time in years)	-0.011755973	0.004194543	-2.80268252	0.017192078	-0.020988101	-0.002523846

[1] Diebold, Francis. *Econometrics - Streamlined, Applied and e-Aware.* March 2016.

It is important to keep in mind that LEI's trend regression approach contrasts to the statistical analysis that Energy Probe attempted to present in Exhibit No. K9.3. Energy Probe is proposing to perform a hypothesis test, specifically a one sample *t* test, on the annual TFP growth rates. Energy Probe's use of LEI's sample data of TFP growth rates as their X variable (or as a "random variable" as suggested by Dr. Schwartz in hearings[2]) is problematic technically, as this data does not meet the necessary criteria discussed by LEI in Exhibit No. K9.2, OPG's response to Energy Probe Memorandum.

[2] Ontario Energy Board. *Transcript Oral Hearing OPG Volume 9 (p. 110-112).* March 20, 2017.

UNDERTAKING J10.3

Undertaking

To provide the math behind the average growth in OPG labour costs per FTE presented on page 22 of SEC's compendium (K10.4). Were amounts disallowed for compensation costs in EB-2013-0321 excluded from this calculation?

Response

The following response was provided by LEI.

Please see the attached Excel file provided by LEI which demonstrates how LEI calculated the average growth in OPG labour costs per FTE from 2002 to 2012, which was presented in the stakeholder information session in 2014.[1] This average growth in OPG labour costs per FTE was calculated using annual data on labour costs and annual data on FTEs for OPG's hydroelectric fleet only, as provided by OPG, and consistent with the O&MA data relied upon in LEI's TFP study.

LEI's calculation (as reproduced at page 22 of SEC's compendium) covered the period from 2002 to 2012. The compensation disallowances made in EB-2013-0321 for 2014 and 2015 were subsequent to that period and did not apply (see the response to Undertaking J10.4 regarding the impact of that disallowance). The OEB has not disallowed hydroelectric compensation amounts in prior applications.

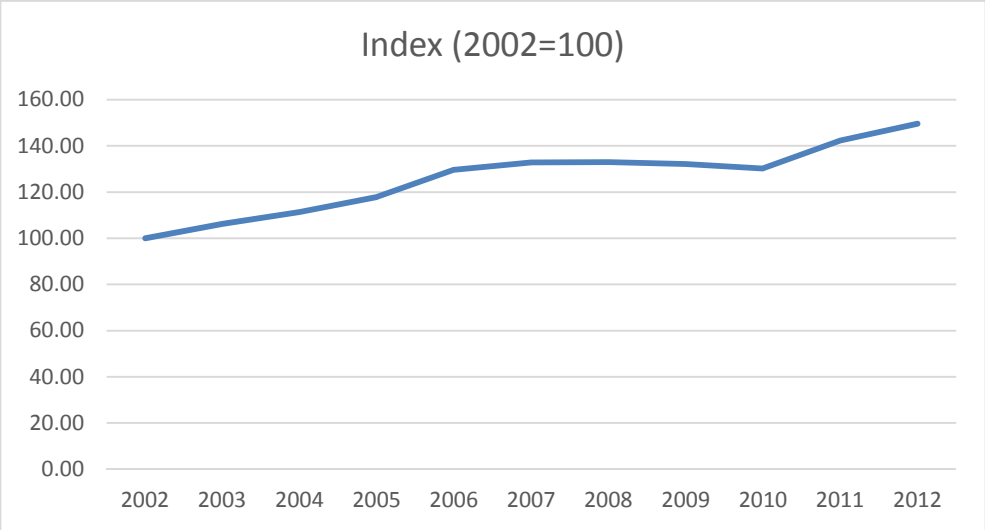
- Attachment 1: Undertaking J10.3 – Calculation of OPG labour cost per FTE

[1] LEI. *Inflation Factor Analysis for OPG Regulated Hydroelectric IRM*. December 17, 2014. P 9. <http://www.opg.com/about/regulatory-affairs/stakeholder-information/Documents/Payment_Amounts/Inflation_Factor_Analysis.pdf>

Year	I # FTEs	I K$ Labour_OM&A	Labour cost per FTE	Index (2002=100)	Growth Rate
2002	878	78,723	89.66	100.00	
2003	883	84,147	95.30	106.28	6.09%
2004	885	88,414	99.90	111.42	4.72%
2005	866	91,483	105.64	117.82	5.58%
2006	866	100,682	116.26	129.67	9.58%
2007	892	106,220	119.08	132.81	2.40%
2008	927	110,503	119.21	132.95	0.10%
2009	963	114,132	118.52	132.18	-0.58%
2010	920	107,412	116.73	130.18	-1.52%
2011	952	121,439	127.58	142.28	8.89%
2012	943	126,510	134.19	149.66	5.05%

Source: OPG, May 21 2014

Average growth in OPG labour costs per FTE 4.03%



UNDERTAKING J10.4

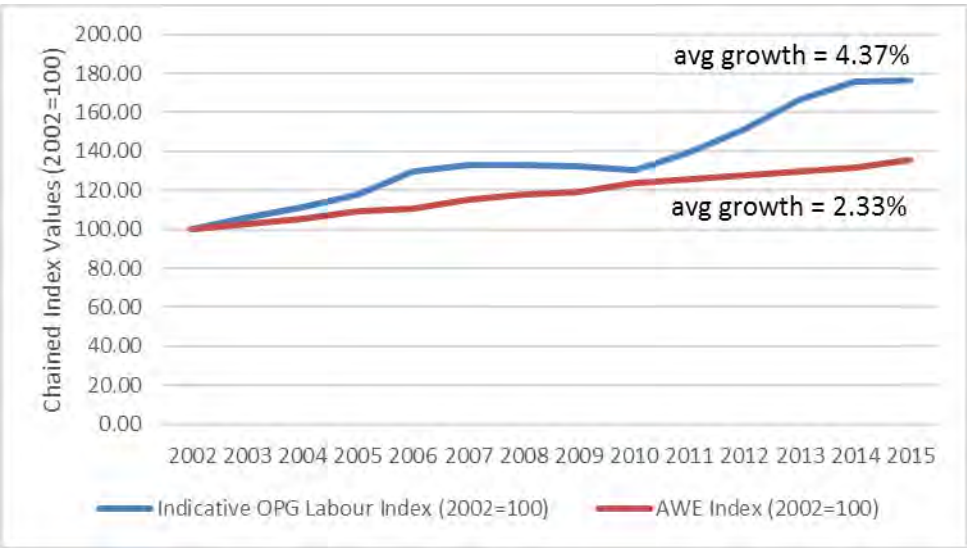
Undertaking

For LEI to extend the calculation Ontario Average Weekly Earnings table from 2012 to 2015.

Response

Please see the attached Excel file provided by LEI which extends the calculation of the average growth in OPG regulated hydroelectric labour costs per FTE to 2015, based on data provided by OPG as of March 28, 2017.[1]

Based on this data extension, the average growth in OPG regulated hydroelectric labour costs per FTE over the 2002 through 2015 period was estimated at 4.37%. As seen in the chart below, OPG's hydroelectric labour costs per FTE have been greater than the average Ontario industrial aggregate Average Weekly Earnings (AWE) since 2002.



Furthermore, based on the additional data for OPG regulated hydroelectric unit labor costs, LEI does not find any evidence to conclude that the inflationary trend in OPG's labour costs will mean revert to the slower inflationary trends observed in the Average Weekly Earnings for Ontario's industrial aggregate.

[1] Note that the O&MA costs for 2011 and 2012 used to calculate the index values in the figure above include updates that were incorporated into LEI's TFP model in 2015, so they are slightly different than the data presented at the 2014 stakeholder information session and included in response to Undertaking J10.3. These updates better reflect the removal of Lower Mattagami stations that were transferred from OPG to the Partnership in 2011.

LEI's assessment of OPG's labour costs demonstrates that using the AWE index to measure OPG's labour costs is conservative. While LEI's analysis did not account for the disallowance of compensation-related costs for 2014 and 2015, LEI concludes that using the AWE index would remain conservative if that disallowance were reflected in the company's labour costs. If the hydroelectric portion of the $100M OM&A reduction in EB-2013-0321 were applied to OPG's 2014 and 2015 labour costs,[2] OPG's labour escalation rate would have been approximately 4%. Note that this calculation applies only the estimated labour-related portion of that disallowance to reduce OPG's labour costs.[3] As a result, LEI's recommendation to use AWE as an index to reflect OPG's labour costs would remain conservative.

- Attachment 1: Undertaking J10.4 – Calculation of OPG labour cost per FTE extended to 2015

[2] The $100M OM&A disallowance is $4.5M in both 2014 and 2015 for previously regulated hydroelectric operations per EB-2013-0321 Payment Amounts Order, Appendix A, Table 1a, footnote 5, line 2b, and $7.8 in 2014 and $7.7M in 2015 for newly regulated hydroelectric operations per EB-2013-0321 Payment Amounts Order, Appendix A, Table 2a, footnote 6, line 2a

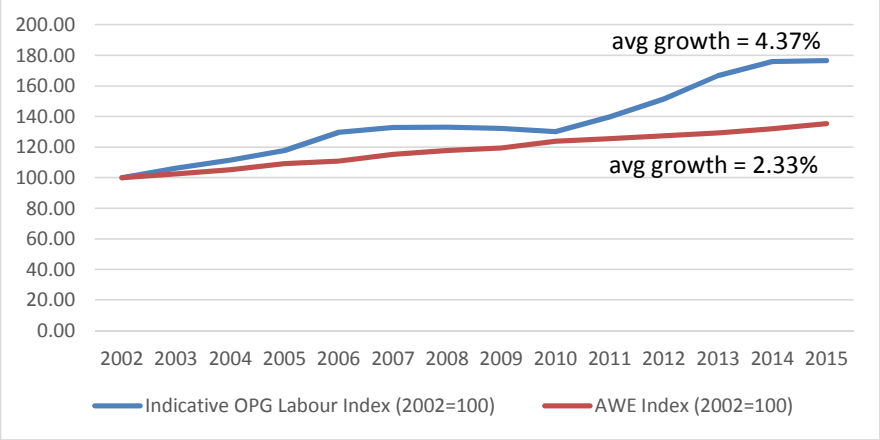
[3] LEI has assumed that the labour to non-labour weights of 64%/36% would apply to the disallowance amounts in completing the calculations. These weights are consistent with OPG's 2002-2014 average labour to non-labour costs. The resultant adjustment to labour OM&A from disallowances is $7.8M in 2014 and 2015.

Year	I # FTEs	I K$ Labour_OM&A	Labour cost per FTE	Indicative OPG Labour Index (2002=100)	Growth Rate	AWE (Ontario industrial aggregate)	AWE Index (2002=100)	Growth Rate
2002	878	78,723	89.66	100.00		711.29	100.00	
2003	883	84,147	95.30	106.28	6.09%	728.70	102.45	2.42%
2004	885	88,414	99.90	111.42	4.72%	748.98	105.30	2.75%
2005	866	91,483	105.64	117.82	5.58%	776.33	109.14	3.59%
2006	866	100,682	116.26	129.67	9.58%	788.78	110.89	1.59%
2007	892	106,220	119.08	132.81	2.40%	819.18	115.17	3.78%
2008	927	110,503	119.21	132.95	0.10%	838.34	117.86	2.31%
2009	963	114,132	118.52	132.18	-0.58%	849.07	119.37	1.27%
2010	920	107,412	116.73	130.18	-1.52%	881.44	123.92	3.74%
2011	882	110,456	125.25	139.69	7.05%	893.44	125.61	1.35%
2012	851	115,567	135.74	151.39	8.04%	906.15	127.40	1.41%
2013	814	121,789	149.54	166.79	9.69%	920.24	129.38	1.54%
2014	760	119,907	157.72	175.91	5.32%	938.27	131.91	1.94%
2015	781	123,707	158.30	176.56	0.37%	962.73	135.35	2.57%

Source: OPG, Mar 28 2017

Source: Statcan, Table 281-0027, accessed on Mar 29 2017

Average growth in OPG Hydroelectric's labour costs per FTE (2002-2015)	4.37%
Average growth in OPG Hydroelectric's labour costs per AWE (2002-2015)	2.33%



UNDERTAKING J10.5

Undertaking

On a best efforts basis, to reconcile average age of hydro plants in LEI's study (66 years) with the average age used in Navigant's study (85 years).

Response

The following response was provided by LEI.

The difference between the average age values in the two studies is mainly due to the fact that LEI calculated a MW-weighted average age, whereas Navigant appears to have used the median age of the facilities included in their study. As shown in the attached spreadsheet, when LEI calculates a median age for OPG's facilities using the data in its study, the result is a median of 87.5 years across the plants' individual ages. This figure compares to Navigant's calculation of 84.5 years (shown on page 8 of Navigant Hydro Benchmarking Study, dated August 17, 2015, filed as Exhibit A1-3-2, Attachment 2).

The attached Excel file shows LEI's calculation of the MW-weighted average age of OPG's hydro fleet of 66 years shown in Figure 15 on page 27 of LEI's TFP Study (dated February 19, 2016; filed as Exhibit A1-3-2, Attachment 1). For this undertaking, LEI calculated a median across the plants' individual ages of 87.5 years.

- Attachment 1: J10.5 – LEI calculated average age of OPG hydro plants

Calculation of MW-weighted average age of OPG hydro plants

Prepared for:
Ontario Power Generation
in support of incentive rate-making for OPG's prescribed assets

Filing reference:
EB-2016-0152
OPG Undertaking J10.5
(from OEB oral hearing on March 20, 2017)

Date: March 28, 2017

Prepared by:
London Economics International LLC
Julia Frayer, Ian Chow, Kelima Yakupova, Jarome Leslie, and Barbara Porto

HYDROELECTRIC PLANT LISTING BY PLANT GROUP BY RIVER SYSTEM FOR LEI'S TFP STUDY

Data provided by OPG			LEI's calculations
Plant name by OPG hydro group	**Capacity (MW)**	**In-Service Year**	**Age (years)**
Niagara PG			
Welland Canal			
Decew Falls ND1	23	1898	118
Decew Falls NF23	144	1944	72
Niagara River			
Sir Adam Beck I	427	1922	94
Sir Adam Beck II	1,499	1954	62
Sir Adam Beck PGS	174	1957	59
Ottawa-St. Lawrence PG			
Madawaska River			
Mountain Chute	170	1967	49
Barrett Chute	176	1942	74
Calabogie	5	1917	99
Stewartville	182	1948	68
Arnprior	82	1976	40
Ottawa River			
Otto Holden	243	1952	64
Des Joachims	429	1950	66
Chenaux	144	1950	66
Chats Falls	96	1931	85
St. Lawrence			
R.H. Saunders	1,045	1958	58
Northwest PG			
Aguasabon River			
Aguasabon	51	1948	68
Nipigon River			
Pine Portage	142	1950	66
Cameron Falls	92	1921	95
Alexander	69	1930	86
Kaministiquia River			
Silver Falls	48	1959	57
Kakabeka Falls	25	1906	110
English River			
Manitou Falls	73	1956	60
Caribou Falls	91	1958	58
Winnipeg River (South Branch)			
Whitedog Falls	68	1958	58
Northeast PG			
Abitibi River			
Abitibi Canyon	349	1933	83
Otter Rapids	182	1961	55
Matabitchuan River			
Matabitchuan	10	1910	106
Montreal River			
Indian Chute	3	1924	92
Lower Notch	274	1971	45
Central Hydro PG			
Mississippi River			
High Falls	2.7	1920	96
Rideau River			
Merrickville	1.7	1915	101
Trent River			
Lakefield	1.8	1928	88
Auburn	2	1911	105
Seymour	5.7	1909	107
Ranney Falls	10.4	1922	94
Hagues Reach	3.6	1925	91
Meyersberg	5.2	1924	92
Sills Island	1.8	1900	116
Frankford	2.6	1913	103
Sidney	4.4	1911	105
Beaver River			
Eugenia Falls	6.1	1915	101
Muskoka River (South Branch)			
Trethewey Falls	1.8	1929	87
Hanna Chute	1.4	1926	90
South Falls	5.0	1907	109
Muskoka (Musquash) River			
Ragged Rapids	8.3	1938	78
Big Eddy	8.0	1941	75
Severn River			
Big Chute	10.0	1993	23
South River			
Elliot Chute	1.6	1929	87
Bingham Chute	1.0	1923	93
Nipissing	1.8	1909	107
Sturgeon River			
Crystal Falls	8.4	1921	95
Wanapitei River			
Stinson	5.4	1925	91
Coniston	4.6	1905	111
McVittie	2.8	1912	104
TOTAL (not incl. sold plants and HESA)	6,422		

	Result
MW-weighted average of plants' ages	66.1
median	87.5

Notes: Data provided by OPG for the TFP Study. The plant list does not include HESA contracts and does not include plants that OPG has sold as of 2014, the last year of LEI's TFP Study.

UNDERTAKING J10.6

Undertaking

TO PROVIDE THE AMOUNT OF CRVA ELIGIBLE CAPITAL SPENDING IN 2016

Response

As this undertaking arose in relation to a discussion of CRVA-eligible in-service additions provided in response to Ex. L.11.1-15 SEC-095 and on pages 3 and 4 of Ex. K10.5 as prepared by SEC, OPG understands the request to be for CRVA in-service additions for 2016.

In 2016, OPG placed less than $1M into service related to CRVA-eligible hydroelectric projects.

UNDERTAKING J10.7

Undertaking

Review of page 6 of SEC's compendium K10.5, and confirm if OPG agrees with numbers and calculations.

Response

OPG's response to this undertaking is limited to an assessment of the input values and mechanical accuracy of calculations in Ex. K10.5, page 6 (the "SEC Scenario"). The SEC Scenario is a simplistic document prepared on a selective basis, and OPG does not believe that it represents a realistic forecast of the trajectory of OPG's revenues or costs during the 2017-2021 period.

OM&A Corrections

The SEC Scenario includes actual 2016 OM&A. SEC has used a 2016 actual OM&A value of $325M, as reported in note 15 of OPG's audited consolidated financial statements published on March 10, 2017. As OPG witnesses informed SEC during cross-examination, the financial statements are not reported on the same basis as otherwise filed with the OEB.[1] As a result, the 2016 actual OM&A value must be corrected to be consistent with the OEB-approved OM&A as used elsewhere in SEC Scenario. The OM&A as reported in the financial statements excludes IESO non-energy charges, which are included in the OEB-approved OM&A, but are presented as a reduction to revenue for financial statement reporting purposes. Correcting for this increases 2016 actual OM&A value by approximately $11.5M. After this correction, the 2016 actual OM&A value would be $336.5M.

The SEC scenario adds one decimal point to the OM&A Escalation Index value (e.g., moving from 2.1% to 2.06% in 2016). OPG does not object to this adjustment, but notes that it appears to be inconsistent with the OEB's methodology used to calculate the inflation index, which rounds the value to a single decimal. However, since the effect of SEC's adjustment is immaterial, OPG does not propose a correction.

CRVA Amounts in Capital Additions

SEC has removed forecast amounts for projects that OPG has identified as related to projects that may be eligible to be recorded to the Capacity Refurbishment Variance Account ("CRVA"), as identified in OPG's response to Ex. L-11.1-15 SEC-095. OPG believes that this exclusion of CRVA-related in-service capital amounts is inappropriate.

[1] Transcript, Day 10, page 64, lines 22-28.

OPG has stated that it does not believe that the CRVA should operate in such a manner as to allow it to recover costs associated with CRVA-eligible projects in payment amounts and then to recover those same costs again through disposition of the CRVA.[2] OPG's proposed approach to ensuring that no "double recovery" takes place is detailed in Ex. H1-1-2.

Since there would be no "double recovery" in connection with the recovery of amounts recorded in the CRVA under OPG's proposal, there is no basis on which forecast CRVA-eligible in-service additions should be excluded from OPG's costs for the purpose of the SEC Scenario. Capital investments related to such projects are part of OPG's capital program and should be included, as they would be in a cost of service rate setting (which the SEC Scenario attempts to emulate). OPG has corrected the SEC Scenario by re-inserting the CRVA-related in-service amounts in the 2017-2021 period that were removed by SEC.

Production Forecast Amounts

If the SEC Scenario is intended to approximate the financial performance of OPG's regulated hydroelectric facilities during the 2017-2021 period, the major inputs to the scenario should reflect the most current information available on the record or through OPG's public filings. SEC has inserted certain 2016 actual values from OPG's 2016 financial statements, but has not included the 2016 actual production.

OPG has corrected the SEC Scenario by including the 2016 actual production value found in OPG's public financial filings, as well as the forecast regulated hydroelectric production values (before SBG) per the 2017-2019 Business Plan (Ex. N1-1-1, Attachment 1, page 5). While the approved payment amounts (i.e., the "going in rates") were based on annual production of 33 TWh, the current business plan includes specific annual forecast amounts for the 2017-2021 period. The reduced production forecast in the business plan is primarily due to operational factors, and not to lower water flows. As such, OPG does not expect to recover the resulting losses in the Hydroelectric Water Conditions Variance Account.

The 2017-2021 Business Plan production forecast represents a more accurate view of OPG's production during the 2017-2021 period than the forecast prepared for 2014 and 2015 period, as filed in EB-2013-0321. Since OPG's payments are 100% variable, this reduced production relative to the amount on which payment amounts were approved, will constitute a significant challenge for OPG during the IR period.

Deficient Revenue during the IR Period

Attachment 1 to this undertaking reflects the corrections described above. The net effect of these corrections is a "prediction" in the SEC Scenario that OPG's revenues will be insufficient by $28M across the 2017-2021 period. Notwithstanding OPG's objections to

[2] Transcript, Day 10, page 33, lines 6-7.

the relevance of the SEC Scenario in an IRM proceeding, the directional implication of the corrected scenario is that OPG will be challenged to achieve its business plan under the payment amounts proposed in this application.

Attachment 1 - OPG Hydroelectric Cost Model (J10.7)

	Component	2014-2015 OEB Approved	2016	2017	2018	2019	2020	2021	2017-2021 Totals	Comparison with SEC Scenario	Notes (Changes Relative to K10.5, Page 6)
		a	b	c	d	e	f	g	h	I	
1	Gross Assets	9,290.2	9,369.2	9,551.2	9,729.2	9,915.2	10,126.2	10,321.2			
2	Accum. Depreciation	1,813.9	1,958.1	2,105.0	2,254.7	2,407.3	2,563.1	2,721.9			
3a	Net Fixed Assets	7,476.3	7,411.1	7,446.2	7,474.5	7,507.9	7,563.1	7,599.3			
3b	Working Capital & Cash Working Capital	31.4	31.4	31.4	31.4	31.4	31.4	31.4			
3c	Net Rate Base	7,507.7	7,442.5	7,477.6	7,505.9	7,539.3	7,594.5	7,630.7			
4	Weighted Average Depreciation Rate		1.54%	1.54%	1.54%	1.54%	1.54%	1.54%			
5	Expected Capital Additions		79.0	182.0	178.0	186.0	211.0	195.0			2017-2021 in-service additions as shown in Ex. L.11.1-1 SEC-095.
6	I factor		N/A	1.80%	1.80%	1.80%	1.80%	1.80%			
7	X-Factor		N/A	0.30%	0.30%	0.30%	0.30%	0.30%			
8	OM&A Escalation Index		2.06%	2.25%	2.25%	2.25%	2.25%	2.25%			
	Costs Associated with Operations										
9	GRC	350.6	350.6	346.0	352.6	349.1	334.7	330.5	1,712.9	(66.6)	Varies with on revised production (reducing GRC cost)
10	OM&A	334.9	336.5	343.1	349.8	356.6	363.5	370.6	1,783.5	31.6	Adjusted to reflect 2016 actual IESO non-energy charges
11	**Total Ops Costs**	685.5	687.1	689.1	702.4	705.6	698.3	701.1	3,496.5	(34.9)	
	Costs Associated with Capital										
12	Depreciation/Amortization	143.3	144.2	147.0	149.7	152.6	155.8	158.8	763.8	28.6	Varies with changes to capital amounts
13	Cost of Debt	199.4	197.7	198.6	199.4	200.3	201.7	202.7	1,002.8	51.3	Varies with changes to capital amounts
14	ROE	315.2	312.5	313.9	315.1	316.5	318.9	320.4	1,584.9	82.6	Varies with changes to capital amounts
15	PILs	78.6	77.9	78.3	78.6	78.9	79.5	79.9	395.2	14.6	Varies with changes to capital amounts
16	**Total Capital Related Costs**	736.5	732.3	737.8	742.8	748.3	755.9	761.8	3,746.6	177.0	
17	**Total Costs**	1,422.0	1,419.3	1,426.9	1,445.2	1,453.9	1,454.2	1,462.9	7,243.1	142.1	
18	**Less Other Revenues**	85.7	65.4	65.4	65.4	65.4	65.4	65.4	327.0	(101.5)	2016 value corrected as per testimony (EB-2016-0152, Transcript, Day 21, page 2)
19	**Net Revenue Requirement**	1,336.3	1,353.9	1,361.5	1,379.8	1,388.5	1,388.8	1,397.5	6,916.0	(243.5)	
20	Payment Amount	$41.09	$41.09	$41.71	$42.33	$42.97	$43.61	$44.27			
21	Production (TWh)	33.0	33.0	32.6	33.2	32.9	31.5	31.1			2017-2021 production amounts per Ex. N1-1-1, Attachment 1, page 5
22	Revenues	1,356.0	1,356.0	1,358.5	1,405.1	1,411.8	1,374.1	1,377.0	6,926.5	(165.2)	
23	Insufficient/Excess Revenues		**2.0**	**(3.0)**	**25.3**	**23.2**	**(14.7)**	**(20.4)**	**10.5**	(408.7)	
24	Cost-Based Payment Amount			$41.80	$41.57	$42.26	$44.08	$44.92			
25	Difference			-$0.09	$0.76	$0.71	-$0.47	-$0.66			
26	Insufficient/Excess Revenues			-3.0	25.3	23.2	-14.7	-20.4			
27	Percent			-0.22%	1.84%	1.67%	-1.06%	-1.46%			

UNDERTAKING J11.1

Undertaking

To provide an explanation of the Table at page 37 of Exhibit K10.4

Response

The following response was provided by PEG:

The first three columns of values (capacity increase, percentage increase, plant additions) are straightforward calculations based on information provided in the working papers. The calculations behind the economic depreciation column warrant additional discussion. This depreciation calculation is consistent with the productivity work done by PEG. Therefore, the "Economic Depreciation" on this table is not straight-line. It is rather the value of the quantity of capital that has depreciated. This quantity is calculated as the economic depreciation rate (2.63%) multiplied by the beginning of year capital quantity. The price that is multiplied by the depreciated quantity to obtain the value of depreciation is the asset price index used in the study. These calculations were done for each year. The values on the table represent the sum of the annual depreciation amounts for 1996-2014. The supporting calculations and data for plant additions, capacity, asset price, capital quantity, MFP and depreciation rate were provided as part of the PEG working papers.

UNDERTAKING J11.2

Undertaking

To reproduce Energy Probe's Figure 1 at page 10 of Exhibit K10.1 using PEG's data.

Response

The following response was provided by PEG:

PEG believes that Energy Probe Table 2 from the same exhibit is an accurate presentation of the growth rates calculated in the PEG working papers. These calculations are contained in the "indexes" worksheet of PEG-WP-1.xls in column AE.

UNDERTAKING J11.3

Reference:

For hydroelectric generation, the economic depreciation rate was set at 2.63%. It was based on the assumption of a 100-year average service life for structures and a 52-year average service life for equipment.

Undertaking

To advise whether the assumption that was used would not have categorized the Niagara Tunnel as a structure.

Response

The following response was provided by PEG:

This statement was made after an examination of the information on asset types and service lives provided by OPG in response to Board Staff #247. The document provided (EB-2013-0321 Ex F5-3-1) predates the Niagara Tunnel Project. The categories of assets provided were reviewed to determine if they were structures or equipment. All asset classes listed as having a 100-year life appeared to be structural and the remainder appeared to be equipment. The statement in the report was descriptive of what was done based on the information provided as opposed to an a priori assumption by PEG of the service life of hydro structures.

In response to the hypothetical posed by OPG counsel, where the data included the Niagara Tunnel Project ("NTP"), PEG believes that the NTP would have been classified as a structure. Had the NTP been part of the evidence provided, there are at least two different ways that these data would have been presented. Both would have led to the relevant portion of the NTP being classified as structure.

The first possibility is that the NTP would have received its own entry on the table with a 95-year service life assigned. In this event, PEG would have identified it as a structure and either assigned it a 100-year service life or revised the average service life of structures slightly downward.

The second possibility is that the cost of NTP would have been decomposed. We speculate that in this event the vast majority of the project would have been assigned to the either:
HYDROELECTRIC - SUBSTRUCTURES AND SUPERSTRUCTURES
or HYDROELECTRIC - EXCAVATION, DREDGING, RIPRAPPING AND GROUTING,

both of which had a 100-year lives assigned. The cost of the tunnel lining could have been assigned to HYDROELECTRIC - LINING OF TUNNELS AND PERMANENT SHAFTS which is assigned a lower life of 75 years. Our understanding is that the lining of the NTP was designed to be quite durable and very well may have a life closer to that of the tunnel structure.

It is unknown how service life assumptions might change in a new depreciation study that took account of the NTP. However, it is a simple matter to test the hypothetical impact on the PEG calculation if all structures were assumed to have a 95-year life instead of a 100-year life. Using the working papers provided (PEG-WP-2), a simple substitution of 95 for 100 in the “Depreciation Rate” worksheet yields a depreciation rate of 2.61% vs. 2.63%. We do not consider this to be a material change.

UNDERTAKING J12.1

Undertaking

To provide the assumed forced outage rate estimated for gas generation in IESO analysis (Reference Ex F2-2-3, Attachment 1, page 6).

Response

Existing gas-fired generators included in the IESO analysis show a total weighted average forced outage rate of approximately 5% (although forced outage rates can vary depending on the specific generator and can also vary over a given generator's service life).

In scenarios of no Pickering Extended Operation, assumed additions of peaking generation were represented as capacity with a 0% (zero percent) forced outage rate. While this assumption of performance understates the forced outage rate of a real natural gas-fired generator, it was adopted for convenience and is not expected to materially impact the results of the IESO's analysis of Pickering Extended Operation.

UNDERTAKING J12.2

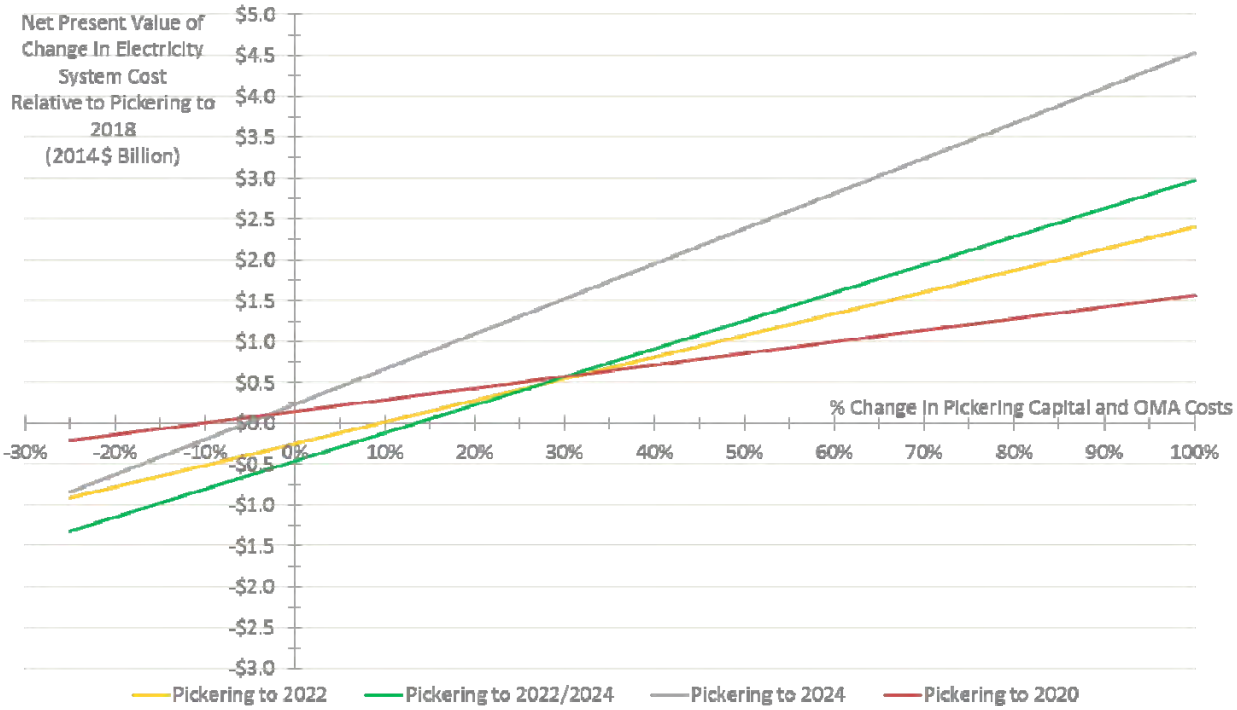
Undertaking

Compare Pickering 2022 to 2018 base cases, what is the tipping point at which project becomes uneconomic relative to that base case (See chart on page 62 of Ex F2-2-3, Attachment 1).

Response

If Pickering to 2018 was used as a base case instead of Pickering to 2020, the cost/benefit sensitivity to a change in Pickering capital and OMA costs would appear as shown in the figure below. The figure shows that Pickering life extension to 2022/2024 would not be economic if Pickering costs increased by more than 13.4 percent.

Figure 1



UNDERTAKING J12.3

Undertaking

To provide breakdown of -$1.4B NPV of Change in Electricity System Cost Components Relative to Pickering to 2020 between domestic generation (i.e. gas fired) and imports. Import types to be provided on best efforts basis (See chart in Ex. F2-2-3, pg. 6).

Response

The -$1.4B NPV (Case with +62 TWh of Pickering Production) due to Change in Electricity System Cost Components Relative to Pickering to 2020 is comprised of the following NPV changes in electricity production costs:

Fuel Type	NPV Savings ($2015M)
Natural Gas	-675
Imports	-740

The net change in imports by jurisdiction is as follows:

Jurisdiction	Total change in Imports between 2015 and 2024 (TWh)
New York	-8.7
Quebec	-4.3
Michigan	-4.9
Manitoba	-1.9
Minnesota	-0.4

*negative figures indicate a reduction relative to the Pickering to 2020 case.

In any given hour, imports and exports among neighbouring jurisdictions reflect an interplay of real-time electricity prices, electricity demands, bidding practices, carbon costs, resource and transmission availability and other factors. Long-term annual projections of electricity trade are accordingly interpreted as indicative in light of the uncertainties in projecting any of these factors across a wide range of control areas. In practice, imports into Ontario could be lower or higher, as could the output of flexible resources in the province such as natural gas-fired generators. Imports and Ontario-based natural gas-fired generators often work in tandem as swing resources – projections of their combined annual volumes are likely more indicative than if considered individually.

UNDERTAKING J12.4

Undertaking

To assess whether the $148M in savings on GEC compendium page 35 would increase with a decrease in Pickering production from 73 to 62 MWh.

Response

The increase in Pickering production (62, 65 or 73 TWh) is relative to the base case of all Pickering units being retired at the end of 2020. In the case where all Pickering units are retired at the end of 2018, total Pickering production decreases by 41 TWh relative to 2020 Base Case. All costs and savings for the Pickering to 2018 case are calculated relative to the 2020 Base Case.

The $148M in cost savings associated with the Pickering to 2018 case are unrelated to the Pickering extension scenarios, in which Pickering production is increased. Changing the amount of Pickering production in the Pickering extension scenarios will change the cost/benefit analysis for those cases; however, those changes have no impact on the Pickering to 2018 case.

For further reference, this question was discussed in EB-2016-0152 Transcript Volume 12 at pages 69 through 72 (March 24, 2017).

UNDERTAKING J12.5

Undertaking

To confirm NERC numbers on page 27 of GEC compendium are on consistent basis with IESO numbers used in analysis. If not, adjust numbers to be on consistent basis.

Response

The annual peak demand values contained in the 2016 NERC LTRA Narrative Guide on page 27 of the GEC compendium (K12.1) are not on an entirely consistent basis with the peak demand values used in IESO's analysis of Pickering Extended Operations (at F2-2-3 Att.1).

The NERC LTRA focuses on "grid demand" and therefore reflects the IESO's forecast of electricity demand on the IESO-Controlled Grid. Grid demand represents the need for electricity to be delivered to distributors and directly-connected wholesale customers through the bulk electricity system.

In contrast, demand values used in IESO's analysis of Pickering scenarios reflects so-called "net demand", which is the grid demand plus the generation that occurs on the distribution system (i.e. grid demand is a subset of net demand). A net demand representation will be higher than a grid demand representation because it includes demands served by embedded resources that are explicitly modelled as supply resources in long-term planning analyses.

The table below shows the 2016 NERC LTRA demand forecast, adjusted to the Net Demand Forecast level.

2018	2019	2020	2021	2022	2023	2024	2025	2026
24,073	24,030	23,946	24,094	24,131	24,189	24,186	24,243	24,212

UNDERTAKING J12.6

Undertaking

To produce annual Pickering production by year that was used by IESO for purposes of the study (Fall 2015 assessment).

Response

The following table summarizes annual Pickering production as simulated by the IESO in its October 2015 assessment of Pickering Extended Operations. The Table is extracted from the IESO's response to an Interrogatory at Exhibit L, Tab. 6.5, Schedule 7, ED-028, page 3 of 5.

Table 1: Annual Pickering Generation Across Various Scenarios Assessed by the IESO in its October 2015 Analysis of Pickering Extended Operations (MWh)

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	23,887,836	23,887,836	23,887,836	23,887,836
2016	21,269,076	21,269,076	21,269,076	21,269,076
2017	20,130,936	19,240,032	20,130,936	19,240,032
2018	20,585,928	19,300,818	20,585,928	19,424,418
2019	21,442,720	19,593,600	20,651,680	19,049,760
2020	24,289,248	20,884,154	23,930,808	19,902,158
2021	-	19,730,040	-	18,963,000
2022	-	21,301,800	-	20,312,064
2023	-	14,836,032	-	13,956,768
2024	-	16,716,336	-	16,295,280

The values contained in far right column in the table above (i.e. the 62 TWh Extended Operations scenario) have been entered into the spreadsheet which accompanies this response at Attachment 1. Attachment 1 was originally produced by Board Staff as part of Board Staff's Compendium for Panel 3A at Ex. K12.3, p. 2. Values entered into Attachment 1 by the IESO are highlighted in yellow.

Line No.s	COMPARISON OF PRODUCTION FORECAST ESTIMATES USED IN PCO ANALYSIS, PEO ANALYSIS AND OPG'S CURRENT APPLICATION												TOTAL (TWH) 2016-2021
1			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
2	OPG PCO Production Forecast (TWH)									N/A	N/A	N/A	N/A	
3	IESO PEO Assumptions Production Forecast (TWH)	Source - L-6.5-1-STAFF 125			21.3	19.2	19.3	19.6	20.9	19.7	21.3	14.8	16.7	120.0
4	**OEB Staff Estimate (based on Staff IR 125 and 126)**	Source - OEB STAFF ESTIMATE			**21.3**	**19.2**	**19.3**	**19.8**	**20.5**	**18.963**				**119.063**
5	IESO Analysis PEO Production Forecast (TWH)	Source - L-6.5-1-STAFF 126	N/A	23.89	21.27	19.24	19.42	19.05	19.90	18.96	20.31	13.96	16.30	117.8
6	OPG Current Application - Production Forecast (TWH)	Source - E2-T1-S1-TABLE 1	20.1	21.2	20.8	19.1	19.2	19.4	19.6	18.8	N/A	N/A	N/A	116.9
7														
8														

9 Notes:
10 N/A - Not applicable
11 PCO - Pickering Continued Operations
12 PEO - Pickering Extended Operations
13 OEB Staff Estimate is calculated using production estimates in Staff IR 125 and adjusted for revisions noted in Chart 2 of Staff IR 126.
Source: Exhibit L/ Tab 6.5/ Schedule 7/ED-028 Page 3 of 5

UNDERTAKING J12.7

Undertaking

Please provide in table format OPG's Production Forecast and the Actual Production for the years 2014, 2015 and 2016. Please provide this information separately for PNGS and DNGS and by unit.

Response

OPG's production forecast (as opposed to Board approved) and actual production for 2014, 2015 and 2016 by station and unit:

Operating Unit	2014 Budget	2014 Actual	2015 Budget	2015 Actual	2016 Budget	2016 Actual
Darlington Unit 1						
TWh	5.8	5.8	6.5	5.5	7.5	7.6
Darlington Unit 2						
TWh	7.5	7.4	6.4	6.4	5.9	5.7
Darlington Unit 3						
TWh	7.5	7.5	5.5	5.0	7.1	6.7
Darlington Unit 4						
TWh	7.5	7.3	6.4	6.5	5.6	5.7
Total Darlington	28.1	28.0	24.8	23.3	26.0	25.7
Pickering Unit 1						
TWh	3.6	3.9	2.9	2.6	3.8	4.2
Pickering Unit 4						
TWh	2.9	2.8	3.8	4.3	2.9	2.4
Pickering Unit 5						
TWh	4.0	4.3	3.0	2.9	4.3	4.4
Pickering Unit 6						
TWh	4.3	4.0	3.1	3.0	4.3	4.0
Pickering Unit 7						
TWh	2.9	2.8	4.3	4.2	2.9	2.8
Pickering Unit 8						
TWh	3.3	2.4	4.3	4.3	2.6	2.2
Subtotal Pickering [Note 1]	20.9	20.1	21.4	21.2	20.8	19.9
Less Adjustment [Note 1]	0.5	0	0	0	0	0
Total Pickering	20.4	20.1	21.4	21.2	20.8	19.9

Note 1: excludes a decrease of 0.5 TWH to the forecast for Pickering in 2014 that was not allocated to specific units (EB-2013-0321 Ex N2-1-1).
Amounts may not add up due to rounding

UNDERTAKING J12.8

Undertaking

Please provide in table format the Actual Planned Outage Days and OPG's Forecast of Planned Outage Days for the period 2008 to 2016. Please provide this information separately for PNGS and DNGS and by unit.

Response

Actual planned outage days and OPG's forecast of planned outage days for the period 2008 to 2016 by station and by unit are provided in Attachment 1. For completeness, Attachment 1 also includes forced extensions to planned outages ("FEPO"). The forecast values in Attachment 1 reflect the OPG Business Plan underpinning OPG's OEB-approved rates.

OPG has determined that there is an error in the reported 2012 actual Pickering planned outage days in EB-2013-0321. There were 326.1 planned outage days, not 352.3 as reported in EB-2013-0321, Ex. E2-1-2 Table 1.

Actual Versus Planned Forecast By Operating Unit 2008-2021

Operating Unit	2008 Forecast	2008 Actual	2009 Forecast	2009 Actual	2010 Forecast	2010 Actual	2011 Forecast	2011 Actual	2012 Forecast	2012 Actual	2013 Forecast	2013 Actual	2014 Forecast	2014 Actual	2015 Forecast	2015 Actual	2016 Forecast	2016 Actual
Darlington Unit 1																		
PO Days (excludes Refurb)	75.1	69.1	31.5	30.1	0.0	0.0	62.8	60.3	0.0	0.0	0.0	0.0	81.4	77.4	47.5	72.0	0.0	0.0
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0
Total	75.1	69.1	31.5	30.1	0.0	0.0	62.8	60.3	0.0	0.0	0.0	0.0	81.4	77.4	47.5	73.8	0.0	0.0
Darlington Unit 2																		
PO Days (excludes Refurb)	0.0	0.0	32.0	32.0	62.3	61.7	0.0	0.0	0.0	6.8	77.9	77.9	0.0	2.8	51.5	50.3	0.0	0.0
FEPO Days	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.7	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	32.0	35.2	62.3	61.7	0.0	0.0	0.0	6.8	77.9	97.6	0.0	2.8	51.5	50.3	0.0	0.0
Darlington Unit 3																		
PO Days (excludes Refurb)	0.0	0.0	79.5	79.5	0.0	4.9	0.0	0.0	70.9	56.8	0.0	0.0	0.0	0.0	95.8	95.8	20.0	22.4
FEPO Days	0.0	0.0	0.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.8	0.0	0.0
Total	0.0	0.0	79.5	87.2	0.0	4.9	0.0	0.0	70.9	56.8	0.0	0.0	0.0	0.0	95.8	101.6	20.0	22.4
Darlington Unit 4																		
PO Days (excludes Refurb)	0.0	0.0	28.7	28.7	56.5	56.5	0.0	0.0	0.0	0.0	66.5	66.5	0.0	11.8	50.8	48.8	91.0	87.7
FEPO Days	0.0	0.0	0.0	1.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	20.1	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	28.7	29.7	56.5	70.4	0.0	0.0	0.0	0.0	66.5	86.6	0.0	11.8	50.8	48.8	91.0	87.7
Total Darlington NGS																		
PO Days (excludes Refurb)	75.1	69.1	171.7	170.3	118.8	123.0	62.8	60.3	70.9	63.7	144.4	144.4	81.4	92.0	245.6	266.9	111.0	110.1
FEPO Days	0.0	0.0	0.0	11.9	0.0	13.9	0.0	0.0	0.0	0.0	0.0	39.8	0.0	0.0	0.0	7.7	0.0	0.0
Total	75.1	69.1	171.7	182.2	118.8	137.0	62.8	60.3	70.9	63.7	144.4	184.2	81.4	92.0	245.6	274.6	111.0	110.1
Pickering Unit 1																		
PO Days	0.0	0.0	0.0	0.0	98.0	98.0	0.0	0.0	106.3	106.3	0.0	0.0	20.0	0.0	101.7	128.4	33.7	0.0
FEPO Days	0.0	1.1	0.0	0.0	0.0	12.3	0.0	0.0	0.0	9.9	0.0	109.7	0.0	0.0	0.0	17.3	0.0	0.0
Total	0.0	1.1	0.0	0.0	98.0	110.3	0.0	0.0	106.3	116.2	0.0	109.7	20.0	0.0	101.7	145.7	33.7	0.0
Pickering Unit 4																		
PO Days	67.0	0.0	74.0	74.0	47.0	46.5	80.9	80.9	0.0	18.0	99.5	20.0	85.3	85.3	28.0	0.0	107.8	107.8
FEPO Days	0.0	0.0	0.0	32.5	0.0	0.0	0.0	6.8	0.0	7.4	0.0	4.5	0.0	34.3	0.0	0.0	0.0	31.9
Total	67.0	0.0	74.0	106.5	47.0	46.5	80.9	87.7	0.0	25.4	99.5	24.5	85.3	119.6	28.0	0.0	107.8	139.7
Pickering Unit 5																		
PO Days	0.0	1.7	50.0	57.3	45.0	41.9	113.0	113.0	0.0	0.0	87.8	87.8	23.0	0.0	105.9	105.9	0.0	0.0
FEPO Days	0.0	5.3	0.0	27.7	0.0	0.0	0.0	63.9	0.0	0.0	0.0	53.4	0.0	0.0	0.0	14.7	0.0	0.0
Total	0.0	7.0	50.0	85.0	45.0	41.9	113.0	176.9	0.0	0.0	87.8	141.2	23.0	0.0	105.9	120.6	0.0	0.0
Pickering Unit 6																		
PO Days	0.0	0.0	52.0	68.2	42.0	39.4	106.0	101.1	0.0	0.0	116.2	113.0	0.0	0.0	103.8	102.4	0.0	1.4
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2
Total	0.0	0.0	52.0	68.2	42.0	39.4	106.0	101.1	0.0	0.0	116.2	113.0	0.0	0.0	103.8	102.4	0.0	17.6
Pickering Unit 7																		
PO Days	52.0	0.0	0.0	0.0	128.0	117.2	0.0	0.0	107.4	104.4	0.0	0.0	113.9	113.9	0.0	0.0	117.5	117.5
FEPO Days	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	8.5	0.0	3.9
Total	52.0	0.0	0.0	0.0	128.0	119.4	0.0	0.0	107.4	104.4	0.0	0.0	113.9	121.4	0.0	8.5	117.5	121.4
Pickering Unit 8																		
PO Days	60.0	60.4	0.0	0.0	76.0	76.4	0.0	0.0	97.4	97.4	0.0	0.0	85.7	85.7	0.0	13.4	142.6	142.6
FEPO Days	0.0	13.2	0.0	0.0	0.0	7.0	0.0	0.0	0.0	8.9	0.0	0.0	0.0	13.6	0.0	0.0	0.0	41.4

UNDERTAKING J12.9

Undertaking

Please expand VECC IR19 (EX L-TAB 5.1-SCHEDULE 20 VECC 19, ATTACHMENT 1) to include the years 2008 to 2016 and year 2021. Please provide actuals for 2016.

Response

An update to Ex L-Tab 5.1-Schedule 20 VECC 19, Attachment 1 to include the years 2008 to 2016 and year 2021 has been provided in Attachment 1.

Actual/ Planned Forecast By Operating Unit 2008-2021

Operating Unit	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Darlington Unit 1														
TWh	6.1	6.9	7.2	6.2	7.3	7.5	5.8	5.5	7.6	5.2	7.1	7.0	5.2	3.3
Unit Capability Factor (%)	80.8	91.0	95.7	82.8	95.6	98.5	75.7	72.4	99.7	69.6	93.6	92.9	69.7	99.0
PO Days (excludes Refurb)	69.1	30.1	0.0	60.3	0.0	0.0	77.4	72.0	0.0	108.4	20.0	22.5	108.2	0.0
Refurb PO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	0.1	0.6	4.3	0.4	4.4	1.3	2.2	8.3	0.2	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	0.2	2.0	15.6	1.1	15.9	4.6	6.1	23.9	0.7	2.6	3.4	3.4	2.6	1.7
Darlington Unit 2														
TWh	7.6	6.7	6.2	7.5	7.2	5.1	7.4	6.4	5.7	-0.2	-0.2	-0.2	4.7	6.4
Unit Capability Factor (%)	98.8	88.4	82.5	99.0	94.2	67.6	96.9	84.3	96.5	0.0	0.0	0.0	72.2	85.3
PO Days (excludes Refurb)	0.0	32.0	61.7	0.0	6.8	77.9	2.8	50.3	0.0	0.0	0.0	0.0	57.5	33.7
Refurb PO Days				0.0	0.0	0.0	0.0	0.0	78.0	365.0	365.0	365.0	45.0	0.0
FEPO Days	0.0	3.2	0.0	0.0	0.0	19.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	1.2	2.0	0.7	1.0	3.7	7.1	2.2	2.0	3.0	0.0	0.0	0.0	12.0	6.0
FLR Days Equivalent	4.2	6.6	2.0	3.6	13.1	18.8	8.0	6.4	10.8	0.0	0.0	0.0	31.6	19.9
Darlington Unit 3														
TWh	7.7	5.6	7.5	7.6	6.4	7.3	7.5	5.0	6.7	7.0	5.3	7.4	0.8	-0.2
Unit Capability Factor (%)	99.9	74.6	98.5	99.2	84.0	96.6	98.8	65.7	87.7	92.9	71.0	98.3	99.0	0.0
PO Days (excludes Refurb)	0.0	79.5	4.9	0.0	56.8	0.0	0.0	95.8	22.4	22.5	103.3	2.5	0.0	0.0
Refurb PO Days	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	321.0	365.0
FEPO Days	0.0	7.7	0.0	0.0	0.0	0.0	0.0	5.8	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	0.1	1.9	0.1	0.7	0.1	3.4	1.2	8.6	5.9	1.0	1.0	1.0	1.0	0.0
FLR Days Equivalent	0.2	5.2	0.2	2.7	0.2	12.2	4.2	22.4	20.0	3.4	2.6	3.6	0.5	0.0
Darlington Unit 4														
TWh	7.5	6.8	5.6	7.6	7.6	5.2	7.3	6.5	5.7	7.0	7.1	5.4	7.0	7.0
Unit Capability Factor (%)	98.5	89.8	73.8	99.8	99.0	69.0	96.0	85.2	75.5	92.9	93.6	72.1	92.9	92.9
PO Days (excludes Refurb)	0	28.7	56.5	0	0	66.5	11.8	48.8	87.7	22.5	20.0	99.1	22.5	22.5
Refurb PO Days				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FEPO Days	0.0	1.0	13.9	0.0	0.0	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	1.5	2.1	8.5	0.2	0.9	9.3	0.6	1.5	0.2	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	5.3	7.0	25.0	0.8	3.1	25.9	2.1	4.7	0.6	3.4	3.4	2.7	3.4	3.4
Pickering Unit 1														
TWh	2.8	4.1	2.3	3.7	2.9	2.0	3.9	2.6	4.2	1.8	3.7	2.7	3.8	2.5
Unit Capability Factor (%)	62.3	91.7	53.2	82.0	65.2	47.1	87.6	58.0	94.5	41.7	83.8	61.6	83.8	55.8
PO Days	0.0	0.0	98.0	0.0	106.3	0.0	0.0	128.4	0.0	204.9	43.0	128.5	43.0	150.5
FEPO Days	1.1	0.0	12.3	0.0	9.9	109.7	0.0	17.3	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	37.2	8.3	22.2	18.0	4.0	32.2	12.4	2.5	5.0	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	135.0	30.2	55.5	65.9	9.9	81.6	45.1	5.5	18.4	8.0	16.1	11.8	16.2	10.7
Pickering Unit 4														
TWh	3.7	1.6	3.2	2.4	3.3	3.9	2.8	4.3	2.4	3.7	2.6	3.7	2.3	3.9
Unit Capability Factor (%)	81.3	36.7	71.6	53.8	73.8	86.7	63.6	95.3	55.1	83.8	57.5	83.8	52.3	87.2
PO Days	0.0	74.0	46.5	80.9	18.0	20.0	85.3	0.0	107.8	43.0	144.1	43.0	164.5	30.0
FEPO Days	0.0	32.5	0.0	6.8	7.4	4.5	34.3	0.0	31.9	0.0	0.0	0.0	0.0	0.0
FLR (%)	18.6	47.8	17.6	29.2	20.5	6.9	5.3	4.7	10.1	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	68.1	122.5	55.9	81.0	69.8	23.5	12.9	17.3	22.7	16.1	11.0	16.1	10.1	16.8
Pickering Unit 5														
TWh	4.0	3.1	3.8	1.9	4.4	2.6	4.3	2.9	4.4	2.3	4.2	2.3	4.3	2.1
Unit Capability Factor (%)	90.3	70.7	84.6	45.1	98.5	58.7	95.8	66.1	98.9	53.2	95.0	51.9	95.0	48.2
PO Days	1.7	57.3	41.9	113.0	0.0	87.8	0.0	105.9	0.0	160.7	0.0	165.6	0.0	179.7
FEPO Days	5.3	27.7	0.0	63.9	0.0	53.4	0.0	14.7	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	7.2	7.1	3.8	10.4	1.4	1.8	4.1	0.5	1.0	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	25.5	19.8	12.1	19.1	5.2	3.8	14.9	1.1	3.6	10.2	18.3	10.0	18.3	9.3
Pickering Unit 6														
TWh	4.3	3.5	3.9	3.2	4.3	3.0	4.0	3.0	4.0	2.7	4.2	2.1	4.3	2.6
Unit Capability Factor (%)	96.0	78.2	86.3	71.5	97.2	67.6	88.7	68.0	91.7	60.4	95.0	48.1	95.0	57.9
PO Days	0.0	68.2	39.4	101.1	0.0	113.0	0.0	102.4	1.4	133.0	0.0	180.1	0.0	142.6
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	0.0	0.0	0.0	0.0	0.0
FLR (%)	4.1	3.1	3.0	0.5	2.8	0.1	11.3	5.3	2.6	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	14.8	9.2	9.7	1.3	10.2	0.3	41.3	13.8	8.9	11.6	18.3	9.2	18.3	11.1
Pickering Unit 7														
TWh	1.5	4.2	2.9	4.3	2.9	4.3	2.8	4.2	2.8	4.2	2.0	4.2	3.0	3.9
Unit Capability Factor (%)	34.1	94.8	65.4	97.1	66.5	95.4	62.2	93.3	62.5	95.0	44.6	95.0	68.4	87.2
PO Days	0.0	0.0	117.2	0.0	104.4	0.0	113.9	0.0	117.5	0.0	193.5	0.0	102.5	30.0
FEPO Days	0.0	0.0	2.2	0.0	0.0	0.0	7.5	8.5	3.9	0.0	0.0	0.0	0.0	0.0
FLR (%)	65.9	5.2	1.4	2.9	6.5	4.6	6.6	3.3	6.4	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	241.3	18.9	3.3	10.7	16.9	16.7	16.2	11.7	15.7	18.3	8.6	18.3	13.2	16.8
Pickering Unit 8														
TWh	2.9	4.1	3.1	4.1	2.9	3.9	2.4	4.3	2.2	4.2	2.5	4.2	2.0	3.9
Unit Capability Factor (%)	65.3	92.3	69.2	91.0	65.7	86.8	53.8	95.5	48.7	95.0	55.9	95.0	46.0	87.2
PO Days	60.4	0.0	76.4	0.0	97.4	0.0	85.7	13.4	142.6	0.0	150.2	0.0	188.9	30.0
FEPO Days	13.2	0.0	7.0	0.0	8.9	0.0	13.6	0.0	41.4	0.0	0.0	0.0	0.0	0.0
FLR (%)	17.8	7.7	8.9	8.9	6.5	13.2	25.6	0.7	0.6	5.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	51.6	28.0	24.7	32.5	16.8	48.0	67.7	2.3	1.1	18.3	10.7	18.3	8.9	16.8

UNDERTAKING J12.10

Undertaking

Please expand CCC IR 24 (EX L-TAB 5.1-SCHEDULE 5 CCC 24, ATTACHMENT 1) to include the years 2008 to 2016. Please provide actuals for 2016.

Response

An update to Ex. L-5.1-5 CCC-024, Attachment 1 to include the years 2008 to 2016 and actual for 2016 has been provided in Attachment 1.

Please note that the formulas used to calculate total production and total revenue impacts for Darlington in 2020 were incorrect in Ex. L-5.1-5 CCC-024 and have been corrected in the updated table, consistent with Undertaking JT2.14 and J15.13. The corrected formulas result in total 2020 production increasing from 14.8TWh to 18.1TWh. To be clear, however, there is no change in total production impact in 2020 as a result of updating the table to include the years 2008 to 2016.

Year		Unit Affected	Description	Outage Duration (days)	Production (TWe) Impact Due to Outage	Revenue Impact of Outage ($M)
2008	Pickering	Unit 1	FEPO	1.1	0.01	0.7
		Unit 8	Planned Outage	60.4	0.75	39.9
		Unit 8	FEPO	13.2	0.16	8.7
		Unit 5	U/B Planned Outage [1]	1.7	0.02	1.1
		Unit 5	FEPO	5.3	0.07	3.5
				81.8	**1.0**	**4.6**
	Darlington	Unit 1	Planned Outage	69.1	1.48	78.5
				69.1	**1.5**	**87.8**
Total 2008				**150.9**	**2.5**	**92.4**
2009	Pickering	Unit 4	Planned Outage	74.0	0.92	48.8
		Unit 4	FEPO	32.5	0.40	21.4
		Unit 5	Planned Outage	57.3	0.72	37.9
		Unit 5	FEPO	27.7	0.35	18.3
		Unit 6	Planned Outage	68.2	0.85	45.1
				259.7	**3.2**	**101.3**
	Darlington	Unit 3	PO and VBO	79.5	1.70	90.3
		Unit 3	FEPO	7.7	0.16	8.7
		Unit 2	VBO	32.0	0.69	36.3
		Unit 2	FEPO	3.2	0.07	3.7
		Unit 4	VBO	28.7	0.62	32.6
		Unit 4	FEPO	1.0	0.02	1.2
		Unit 1	VBO	30.1	0.65	34.2
				182.2	**3.9**	**206.9**
Total 2009				**441.9**	**7.1**	**308.2**
2010	Pickering	Unit 1	PO and VBO	98.0	1.22	64.7
		Unit 1	FEPO	12.3	0.15	8.1
		Unit 4	VBO	46.5	0.58	30.7
		Unit 5	VBO	42.0	0.52	27.8
		Unit 6	VBO	39.4	0.49	26.1
		Unit 7	VBO	43.0	0.54	28.4
		Unit 7	FEPO	2.2	0.03	1.5
		Unit 8	PO and VBO	76.4	0.95	50.5
		Unit 8	FEPO	7.0	0.09	4.6
		Unit 7	Planned Outage	74.2	0.93	49.1
				441.0	**5.5**	**105.7**
	Darlington	Unit 4	Planned Outage	56.5	1.21	64.2
		Unit 4	FEPO	13.9	0.30	15.8
		Unit 3	U/B Planned Outage [1]	4.9	0.10	5.5
		Unit 2	Planned Outage	61.7	1.32	70.1
				137.0	**2.9**	**314.9**
Total 2010				**578.0**	**8.4**	**365.4**
2011	Pickering	Unit 5	Planned Outage	113.0	1.41	72.7
		Unit 5	FEPO	63.9	0.80	41.1
		Unit 6	Planned Outage	101.0	1.26	64.9
		Unit 4	Planned Outage	80.9	1.01	51.9
		Unit 4	FEPO	6.8	0.08	4.4
				365.6	**4.6**	**121.2**
	Darlington	Unit 1	Planned Outage	55.4	1.19	61.2
		Unit 1	U/B Planned Outage [1]	4.9	0.10	5.4
				60.3	**1.3**	**309.0**
Total 2011				**425.9**	**5.9**	**350.1**
2012	Pickering	Unit 1	Mid- Cycle Planned Outage	20.0	0.25	12.8
		Unit 1	FEPO	0.1	0.00	0.1
		Unit 8	Planned Outage	97.4	1.22	62.6
		Unit 8	FEPO	8.9	0.11	5.7
		Unit 7	Planned Outage	104.4	1.30	67.1
		Unit 1	Planned Outage	86.3	1.07	55.4
		Unit 1	FEPO	9.8	0.12	6.3
		Unit 4	Planned Outage	18.0	0.22	11.6
		Unit 4	FEPO	7.4	0.09	4.7
				352.3	**4.4**	**78.0**
	Darlington	Unit 3	Planned Outage	56.2	1.20	62.1
		Unit 3	U/B Planned Outage [1]	0.6	0.01	0.7
		Unit 2	U/B Planned Outage [1]	6.8	0.15	7.6
				63.7	**1.4**	**170.9**
Total 2012				**416.0**	**5.8**	**226.2**
2013	Pickering	Unit 1	FEPO	109.7	1.37	70.4
		Unit 4	Mid- Cycle Planned Outage	20.0	0.25	12.8
		Unit 4	FEPO	4.5	0.06	2.9
		Unit 5	Planned Outage	87.8	1.10	56.5
		Unit 5	FEPO	53.4	0.67	34.3
		Unit 6	Planned Outage	113	1.41	72.7
				388.4	**4.8**	**163.4**

Year		Unit Affected	Description	Outage Duration (days)	Production (TWe) Impact Due to Outage	Revenue Impact of Outage ($M)
	Darlington	Unit 4	Planned Outage	66.5	1.43	73.4
		Unit 4	FEPO	20.1	0.43	22.2
		Unit 2	Planned Outage	77.9	1.67	86.0
			FEPO	19.7	0.42	21.8
				184.2	**3.9**	**439.5**
Total 2013				**572.6**	**8.8**	**473.9**
2014	**Pickering**	Unit 4	Planned Outage	85.3	1.06	54.7
		Unit 4	FEPO	34.3	0.43	22.0
		Unit 8	Planned Outage	85.7	1.07	55.1
		Unit 8	FEPO	13.6	0.17	8.7
		Unit 7	Planned Outage	113.9	1.42	78.3
		Unit 7	FEPO	7.5	0.09	5.5
				340.3	**4.2**	**83.8**
	Darlington	Unit 1	Planned Outage	75.3	1.61	83.1
		Unit 2	U/B Planned Outage [1]	2.8	0.06	3.1
		Unit 1	U/B Planned Outage [1]	2.1	0.05	2.3
		Unit 4	U/B Planned Outage [1]	11.8	0.25	15.0
				92.0	**2.0**	**192.9**
Total 2014				**432.3**	**6.2**	**271.2**
2015	**Pickering**	Unit 5	Planned Outage	105.9	1.32	78.4
		Unit 5	FEPO	14.7	0.18	10.9
		Unit 1	Planned Outage	101.7	1.27	75.1
		Unit 1	FEPO	17.3	0.22	12.8
		Unit 6	Planned Outage	102.4	1.28	75.8
		Unit 1	U/B Planned Outage [1]	26.6	0.33	19.6
		Unit 7	FEPO	8.5	0.11	6.3
		Unit 8	U/B Planned Outage [1]	13.4	0.17	9.9
				390.5	**4.9**	**111.6**
	Darlington	Unit 3	Planned Outage	95.8	2.05	121.7
		Unit 3	FEPO	5.8	0.13	7.4
		Unit 3	Planned Outage	48.8	1.05	62.0
		Unit 2	Planned Outage	50.3	1.08	63.9
		Unit 1	Planned Outage	47.5	1.02	60.4
		Unit 1	FEPO	0.6	0.01	0.8
		Unit 1	U/B Planned Outage [1]	24.5	0.53	31.1
		Unit 1	FEPO	1.2	0.03	1.6
				274.6	**5.9**	**227.2**
Total 2015				**665.1**	**10.8**	**348.9**
2016	**Pickering**	Unit 6	Planned Outage	1.4	0.02	1.0
		Unit 6	FEPO	16.2	0.20	12.0
		Unit 4	Planned Outage	107.8	1.34	79.6
		Unit 4	FEPO	31.9	0.40	23.6
		Unit 8	Planned Outage	142.6	1.78	105.5
		Unit 8	FEPO	41.4	0.52	30.6
		Unit 7	Planned Outage	117.5	1.47	86.9
		Unit 7	FEPO	3.9	0.05	2.9
				462.7	**5.8**	**120.5**
	Darlington	Unit 4	Planned Outage	87.7	1.88	111.4
		Unit 3	Planned Outage	19.6	0.42	24.9
		Unit 2	Refurbishment Outage	78.0	1.67	99.1
		Unit 3	U/B Planned Outage [1]	2.8	0.06	3.5
				188.1	**4.0**	**449.3**
Total 2016				**650.8**	**9.8**	**569.7**
2017	**Pickering**	Unit 1	Planned Outage	204.9	2.6	168.0
		Unit 4	Mid-Cycle Outage	43.0	0.5	35.2
		Unit 5	Planned Outage	160.7	2.0	132.0
		Unit 6	Planned Outage	133.0	1.7	109.2
				541.6	**6.8**	**444.4**
	Darlington	Unit 1	Planned Outage	108.4	2.3	152.9
		Unit 2	Refurbishment Outage	365.0	7.8	514.8
		Unit 3	Planned Derate	2.5	0.1	3.5
		Unit 3	PHT Pump Motor Outage	20.0	0.4	28.2
		Unit 4	Planned Derate	2.5	0.1	3.5
		Unit 4	PHT Pump Motor Outage	20.0	0.4	28.2
				518.4	**11.1**	**731.2**
Total 2017				**1,060.0**	**17.9**	**1,175.6**
2018	**Pickering**	Unit 1	Mid-Cycle Outage	43.0	0.5	39.1
		Unit 4	Planned Outage	144.1	1.8	131.2
		Unit 7	Planned Outage	193.5	2.4	176.4
		Unit 8	Planned Outage	150.2	1.9	136.9
	Total			**530.8**	**6.6**	**483.6**
	Darington	Unit 1	PHT Pump Motor Outage	20.0	0.4	31.3
		Unit 2	Refurbishment Outage	365.0	7.8	571.4
		Unit 3	Planned Outage	103.3	2.2	161.7

Year		Unit Affected	Description	Outage Duration (days)	Production (TWe) Impact Due to Outage	Revenue Impact of Outage ($M)
		Unit 4	PHT Pump Motor Outage	20.0	0.4	31.3
	Total			**508.3**	**10.9**	**795.8**
Total 2018				**1,039.1**	**17.5**	**1,279.4**
2019	**Pickering**	Unit 1	Planned Outage	128.5	1.6	129.8
		Unit 4	Mid-Cycle Outage	43.0	0.5	43.4
		Unit 5	Planned Outage	165.6	2.1	167.6
		Unit 6	Planned Outage	180.1	2.2	182.3
	Total			**517.2**	**6.5**	**523.1**
	Darlington	Unit 1	PHT Pump Motor Outage	20.0	0.4	34.8
		Unit 1	Planned Derate	2.5	0.1	4.3
		Unit 2	Refurbishment Outage	365.0	7.8	634.3
		Unit 3	Planned Derate	2.5	0.1	4.3
		Unit 4	Planned Outage	99.1	2.1	172.2
	Total			**489.1**	**10.5**	**850.0**
Total 2019				**1,006.3**	**16.9**	**1,373.1**
2020	**Pickering**	Unit 1	Mid-Cycle Outage	43.0	0.5	48.2
		Unit 4	Planned Outage	164.5	2.0	184.4
		Unit 7	Planned Outage	102.5	1.3	115.1
		Unit 8	Planned Outage	188.9	2.4	212.2
	Total			**498.9**	**6.2**	**560.0**
	Darlington	Unit 1	Planned Outage	108.2	2.3	208.7
		Unit 2	Refurbishment Outage	45.0	1.0	86.8
		Unit 2	Planned Derate	2.5	0.1	4.8
		Unit 2	Post Refurb Mini Outage	55.0	1.2	106.1
		Unit 3	Refurbishment Outage	321.0	6.9	619.2
		Unit 4	Planned Derate	2.5	0.1	4.8
		Unit 4	PHT Pump Motor Outage	20.0	0.4	38.6
	Total			**554.2**	**11.9**	**1069.1**
Total 2020				**1,053.1**	**18.1**	**1,629.1**
2021	**Pickering**	Unit 1	Planned Outage	150.5	1.9	187.3
		Unit 4	Vacuum Building Outage	30.0	0.4	37.3
		Unit 5	Planned Outage	179.7	2.2	224.1
		Unit 6	Planned Outage	112.6	1.4	140.4
		Unit 6	Vacuum Building Outage	30.0	0.4	37.4
		Unit 7	Vacuum Building Outage	30.0	0.4	37.4
		Unit 8	Vacuum Building Outage	30.0	0.4	37.4
	Total			**562.8**	**7.0**	**701.3**
	Darlington	Unit 1	Refurbishment Outage	200.0	4.3	428.3
		Unit 2	Post Refurb Mini Outage	31.2	0.7	66.8
		Unit 2	Planned Derate	2.5	0.1	5.4
		Unit 3	Refurbishment Outage	365.0	7.8	781.6
		Unit 4	Planned Derate	2.5	0.1	5.4
		Unit 4	PHT Pump Motor Outage	20.0	0.4	42.8
	Total			**621.2**	**13.3**	**1,330.2**
Total 2021				**1,184.0**	**20.3**	**2,031.5**

[1] U/B Planned Outage is an Unbudgeted Planned Outage representing an emergent outage that was not included in the approved integrated nuclear outage and generation plan that underpins the business plan, but for which OPG had sufficient time to notify the IESO at least 28 days prior to the start date. Although unbudgeted, this allows the outage to be categorized as “planned” for performance reporting purposes as per WANO industry guidelines

UNDERTAKING J12.11

Undertaking

At E2-T1-S1, p. 4 it is stated that Pickering Extended Operations will require an incremental 637 Planned Outage Days? Please provide a breakdown of the 637 days by year and by PNGS unit? Please also provide a summary of the work that will be executed during each outage.

Response

The 637 incremental planned unit outage days for Pickering Extended Operations are shown by year and by generating unit in the chart below.

Pickering will be undertaking these incremental planned outage days in 2017-2020 to ensure Pickering units are fit for service until 2022/2024. The incremental planned outage scope during each outage is expected to address maintenance and inspection of pressure tubes, steam generators, feeders, 'balance of plant' components, fuel channel work (including fueling machine maintenance) as well spacer location and relocation work, additional steam generator water-lancing and feeder replacements.

Chart 1: Incremental Planned Outage Days by Pickering Unit*

Unit No.	2016	2017	2018	2019	2020	**Total 2016-2020**
P1	0	49	-26	10	0	**33**
P4	0	-14	9	-20	84	**59**
P5	0	3	0	73	0	**76**
P6	0	38	0	76	0	**113**
P7	0	0	99	0	127	**225**
P8	0	0	20	0	111	**131**
Total	**0**	**76**	**102**	**138**	**321**	**637**

* In certain years, on Units 1 and 4, there is a reduction in the number of outage days compared to the 2020 end-of-life scenario. This was caused by a re-optimization of the planned outages to enable the 2022/2024 end-of-life scenario.

UNDERTAKING J12.12

Undertaking

Reference to EB-2013-0321, Ex. E2-1-1, mid-cycle outage days for 2014 took 20 days, but now take 43 days. What has led to this change?

Response

The 2014 mid-cycle outage was undertaken to successfully complete key corrective maintenance and improve equipment reliability work including the 3K3 reliability initiative work (see Ex. F2-1-1 Attachment 4, p. 5), as noted at Tr. Vol.12, p.144. Subsequent mid-cycle outages have longer durations to address various inspection and maintenance work such as completing corrective maintenance backlogs that have persisted for a significant period of time. These outages will provide OPG with higher confidence in the reliable operation of the units and reduced potential for forced outages.

UNDERTAKING J12.13

Undertaking

To provide the cost estimates for the seven other projects and the confidence level around those estimates, if available.

Response

The seven alternatives to the Auxiliary Heating System project, including description of their estimated costs where applicable, are listed in the Business Case Summary filed at EB-2013-0321 as Ex. D2-2-1, Attachment 8-5, pp. 5-6. The confidence levels around the cost estimates provided would have been Class 5.

Pages 5-6 of the Business Case Summary have been re-filed here as Attachment 1.

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

OPG-FORM-0076-R003*

Type 3 Business Case Summary

Part C: Other Alternatives

Base Case: Status Quo – No Project

The option of Status Quo (Do Nothing) is not recommended. The existing Construction Boilerhouse does not meet a unavailability target of 1×10^{-2}. Additionally, the condition of the systems, structures and components has been assessed under CCA's which indicate that the piping and pipe supports require immediate field work. Other components require attention within the next 1-5 years. Furthermore, the existing boilerhouse only supplies 45,000 kg/hr steam, while the new Design Requirements indicate the back-up steam required is 110,000 kg/hr.

Alternative 2: Delay Work – Delay Construction of New AHS Facility

This option is not recommended. The priority of the project is tied to the next station Vacuum Building Outage and the results of the CCAs. The project is required to be completed prior to the next station Vacuum Building Outage in 2015 to provide steam for TRF processes and heating to the station. In addition, delaying this project will result in significant OM&A costs (foundation upgrades, pipe maintenance in the pits, etc.) to the existing boiler house identified in the CCAs. This alternative was considered and eliminated, therefore, not included in the financial evaluation.

Alternative 3: Boiler Rental

Boiler rental from an external company is not recommended. Two different options of Boiler rental were preliminarily examined; delivery of portable boilers during an emergency situation and on-site rental units.

The most critical disadvantage of delivery during an emergency situation is the high potential for significant delays before full capacity steam is available and provided for use in the plant, due to reliance on an external company and the logistics involved in mobilization, transportation to site, and set-up in an emergency situation. Estimates range from 24-36 hours before the boiler units reach site, plus additional connection time before steam will be available.

Further disadvantages include:

- High stresses induced in boiler components and structures due to difficulties in alignment during installation or sagging foundation over time,
- Portable boilers generally have horizontal cylindrical design to allow transportation on highways, and as a result, may require larger footprints than stationary boilers, and
- Capacity of a portable boiler is currently limited to about 34,000 kg/hr (for highway transportation), hence 3-4 units would be required to satisfy the required demand.

Although larger portable boiler units are available for rental and could be transported by freight for installation on-site, this alternative is also not desirable due to the following:

- The boilers would still require a small enclosure and heat tracing on the feed water piping for protection from the elements,
- Portable boilers and equipment on the skid would not be tagged to OPG standards. As such, a contract with a third party would be required for maintenance and operation (approximately $200-400K / year, budgetary), and
- Rental costs for the required size / number of portable units is estimated at approximately $180K/month ($2.2M / year), depending on the length of the contract.

Furthermore, similar to the recommended option, boiler rental will still require installation of steam, condensate, fuel and demineralized water tie-ins to the station and possibly installation of new electrical lines to support the rental units.

Alternative 4: Construct New AHS Facility with Black Start Capability

This alternative was considered and eliminated. This would add approximately $20M to the total initial project costs of Alternative 1, plus an additional $0.75M in maintenance costs per year totalling ~ $45M from 2015 to 2055. Two independent assessments were obtained: an economic risk assessment performed internally by Nuclear Finance, and a Black Start economic assessment performed externally, which both concluded that it is not economically justified to include a Black Start capability into the new AHS. This alternative is, therefore, not included in the economic analysis of this BCS.

Alternative 5: Refurbish Existing Construction Boilerhouse

Similar to the Base Case, Refurbishment of the existing Construction Boilerhouse is not recommended based on the fact it does not meet the minimum unavailability target, nor does it supply the required amount of steam per the Design Requirements.

Alternative 6: Alternative Fuel Supplies

Alternative fuel supplies were examined for the AHS including electric, gas, and electric/oil combination fired boilers. These types of boiler facilities are not recommended. The cost to install new electric transmission lines and a switchyard, or natural gas transfer lines to site is in excess of $6M (per preliminary estimates). Dealing with two types of technology for combination boilers adds further logistical and cost concerns. Considering the Boilerhouse facility does not operate frequently, the additional costs associated with installation are not justified.

ONTARIO POWER GENERATION

Records File Information:
See Guidance Section

Type 3 Business Case Summary

Alternative 7: Co-Generation Plant

A Co-Generation plant is not recommended due to the high initial investment cost of approximately $100M. There are also no corporate drivers to support this alternative at this time. Additionally, it is unlikely that real estate would be available at Darlington to site the co-generation plant in such a way that the steam transmission lines can be kept reasonably short. Delays due to likely need for an environmental assessment will make meeting the project schedule impossible.

Part D: Project Cash Flows

k$	LTD	2012	2013	2014	2015	2016	2017	Future	Total
Currently Released	1,429	2,677	3,330						7,436
Requested Now	-	(1,033)	10,762	23,298					33,027
Future Required	-			2,317	2,625	202			5,144
Total Project Cost	1,429	1,644	14,092	25,615	2,625	202			45,607
Ongoing Costs	-								
Grand Total	1,429	1,644	14,092	25,615	2,625	202			45,607

Estimate Class:	Class 3	**Estimate at Completion:**	$ 39,056 k	**OAR Approval Amount:**	$ 45,607 k

Additional Information on Project Cash Flows (optional):

Grand Total does not include ongoing operating costs (Darlington Station OM&A).

Part E: Financial Evaluation

k$	Preferred Alternative - New AHS Facility	Alt 3 - Boiler Rental	Alt 5 - Refurb Boilerhouse	Alt 6 - Alternate Fuel	Alt 7 - Co-Gen Plant
Project Cost	(37,627)	(47,581)	(42,609)	(46,090)	(121,432)
NPV (after tax)	(29,490)	(46,654)	(34,574)	(35,993)	(89,217)
Other (e.g., LUEC)	N/A	N/A	N/A	N/A	N/A

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

(1) Discount rate of 7%.

(2) Escalation rate of 2%.

(3) Interest rate of 5% on capital costs.

(4) Ongoing Operating & Maintenance Costs used for NPV calculations are based on Project high level estimates. Operating & Maintenance Costs that are not incremental were not included in the NPV calculations.

(5) The NPV values are after tax $2012.

(6) Project Costs include demolition costs.

UNDERTAKING J13.1

Undertaking

TO ADVISE WHETHER THE TARGETS THAT WERE SET IN THE PHASE 2 SCOTTMADDEN REPORT WERE IN OPG'S BUSINESS PLANS FILED IN 2009.

Response

Yes, with three exceptions, the 2014 targets that were set out in ScottMadden Phase 2 Report (EB-2010-008, Ex. F5-1-2, p. 16 of 64) and the 2014 targets set out in OPG's 2010-2014 Business Plan (EB-2010-0008, Ex. F2-1-1, Attachment 1, p. 10) are the same.

The exceptions are:

- Darlington WANO NPI: ScottMadden Report (98.6); OPG Business Plan (99.1)
- Darlington 1 year Online Elective Maintenance: ScottMadden (218); OPG Business Plan 214)
- Darlington 1-year Online Corrective Maintenance: ScottMadden (5); OPG Business Plan (4)

The exceptions arose due to the timing of the Phase 2 work undertaken by ScottMadden and the finalization of the OPG 2010-2014 Business Plan. In June 2009, as part of the target setting process, ScottMadden provided assistance that enabled OPG site and support units to set initial 2014 operational and financial targets. Subsequently, after Phase 2 was complete, OPG finalized its operational and financial targets in the 2010-2014 Business Plan dated November 19, 2009.

UNDERTAKING J13.2

Undertaking

To confirm date received report from ScottMadden re *Evaluation of OPG Proposed Approach to Normalize Cost Metrics During Darlington Refurbishment*.

Response

OPG issued a Purchase Order dated August 2, 2016 engaging ScottMadden to examine OPG's proposed approach to normalizing TGC/MWh (L-1.2-2 AMPCO-001, Attachment 3b).

OPG received a final report from ScottMadden on February 8, 2017.

UNDERTAKING J13.3

Undertaking

To provide 2016 actual FTEs for nuclear business.

Response

Please see below an update to Ex. F2-1-1, Table 3 for 2016 actual FTE numbers.

Nuclear Staff Summary - Regular and Non-Regular (FTEs)[1]

Line No.	Group	2013 Actual[2]	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NUCLEAR OPERATIONS:									
1	**Regular Staff**	5,870.7	5,626.7	5,430.4	5,341.1	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
2	**Non-Regular Staff**	496.9	578.1	670.0	843.8	614.4	646.6	632.2	526.8	420.4
3	**Subtotal Nuclear Operations**	6,367.6	6,204.8	6,100.4	6,184.9	6,325.2	6,312.8	6,234.3	6,030.9	5,815.1
	DARLINGTON REFURBISHMENT:									
4	**Regular Staff**	282.0	307.2	329.7	422.6	587.2	599.9	620.5	589.5	597.8
5	**Non-Regular Staff**	24.6	35.3	60.7	112.7	153.2	152.2	137.4	157.7	230.1
6	**Subtotal Nuclear Generation Development**	306.6	342.5	390.4	535.3	740.4	752.1	757.9	747.2	827.9
7	**Total Nuclear**	6,674.2	6,547.3	6,490.8	6,720.2	7,065.6	7,064.9	6,992.2	6,778.1	6,643.0

1 Nuclear Operations and Darlington Refurbishment FTEs are aligned to where costs related to the FTEs are incurred.

2 The 2013 Actual FTEs shown are adjusted from those provided in EB-2013-0321, Ex. J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

UNDERTAKING J13.4

Undertaking

To clarify the issue of the 1300 FTE difference between Goodnight benchmark and OPG's actual as-filed numbers.

Response

As shown in Ex. L-6.2-1 Staff-109 Chart 1, in addition to the 2,036 FTEs not benchmarked by Goodnight (Ex. F2-1-1, p.14), there were 1,310.4 FTEs included in OPG's 2014 actual FTEs (Ex. F4-3-1 Attachment 1) that were excluded from Goodnight benchmarking. The 1,310.4 FTEs consisted of indirect corporate staff (545.4 FTEs) plus non- regular staff not benchmarked, security staff and other (e.g., timing differences) (combined 765.0 FTEs). These types of exclusions are consistent with previous Goodnight benchmarking studies.

Indirect corporate staff (e.g., treasury, tax, etc.) were incorrectly shown on p. 14 of the Goodnight report (Ex. F2-1-1) under the heading Other Exclusions. However, these FTEs are not reflected in the 2,036 FTEs because they are not dedicated to the nuclear business. The 2,036 FTEs represent dedicated regular staff nuclear personnel, which Goodnight assessed and ultimately determined could not be benchmarked.

Security staff was also incorrectly shown as included in Other Exclusions. These FTEs were also not reflected in the 2,036 FTEs because Goodnight never assessed them for inclusion or exclusion from benchmarking. As stated in JX17.9, OPG is not permitted to release security protected prescribed information pursuant to Sections 21 (1)(c) and 23(1) of the General Nuclear Safety and Control Regulations under the *Nuclear Safety and Control Act*. Non Regular staff not benchmarked are also excluded from the 2,036 FTEs, as the 2,036 FTEs represent regular staff only.

As a result, total non-benchmarked FTEs would include the 2,036 nuclear personnel FTEs, the 545 indirect corporate staff FTEs and the 765.0 FTEs associated with non-regular staff not benchmarked, security staff and other (timing differences).

UNDERTAKING J13.5

Undertaking

To provide any written communication (received in 2017) from the CNSC regarding the status of the CNSC drug testing initiative and requirements.

Response

OPG has received two written communications from the CNSC in 2017 regarding the status of the CNSC drug testing initiative and requirements. The two emails are attached as Attachments 1 and 2.

-----Original Message-----

Robin:

There will be a formal announcement on Monday, but it's not going to the Commission in March. The new date is still to be determined.

I have cc'd Maury as he had asked the same question last week.

Brian

-----Original Message-----

Good afternoon.
I am checking on the status of this Regulatory Document, which I understand is expected to be presented to the Commission at the March 8/9 Meeting.

Can you please confirm, when will this document be sent out? We will need to review it prior to the Commission Meeting.

Thank you.

Robin Manley
OPG

Hello,
Thank you for your ongoing interest in REGDOC-2.2.4 *Fitness for Duty*. Please be advised the REGDOC presentation to the Commission has been postponed and will not go forward in March 2017. The new date is still to be determined and an email will be sent informing you of the new date once details are finalised.

Thanks for your continued interest in this document. If you have any questions please contact Jason Churchill.

Regards,

Brian Torrie

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Directeur général, Direction de la politique de réglementation /Direction générale des affaires réglementaires
Commission canadienne de sûreté nucléaire / Gouvernement du Canada
brian.torrie@canada.ca / Tél: 613-947-3728

Please note that my new email address is brian.torrie@canada.ca.
A noter que ma nouvelle adresse courriel est brian.torrie@canada.ca

UNDERTAKING J13.6

Undertaking

Reference: K13.2, p. 14.

To provide how many employees assumed to be let go as part of the calculation of the $247M in severance. And provide an explanation of basis of estimate and determination of $247M savings.

Response

As part of the economic assessment of Pickering Extended Operations, OPG estimated approximately $247M (2015 PV$) of incremental savings associated with severance and related costs anticipated to be incurred upon closure of the Pickering station. These savings represent the difference between the present value of the estimated costs assuming a 2020 shutdown date and the present value of such costs assuming Pickering operations are extended to 2024 (2 units to 2022; 4 units to 2024). The estimated costs reflect assumptions related to the number of affected employees and downsizing process.

The estimated severance and related costs assuming a Pickering 2020 shutdown are based on the exit of approximately 3,300 regular employees. This decline in staffing levels is assumed to occur over several years, reflecting declining demand, activities necessary to safely defuel, dewater and otherwise prepare the units for the safe storage period, and existing collective agreement provisions. In order to estimate the severance and related costs for Pickering Extended Operations, the costs associated with the 2020 shutdown scenario were largely time-shifted to periods consistent with Pickering Extended Operations. The $247M (2015 PV$) of resulting incremental savings largely represents the impact of the time value of money of deferring these costs.

UNDERTAKING J13.7

Undertaking

Reference : JT1.17

TO PROVIDE AN AVAILABLE ECONOMIC ANALYSIS OF THE IMPACT OF DECOMMISSIONING.

Response

Attachment 1 is OPG's assessment entitled, "A Preliminary Assessment to Determine the Financial Impact of Using a Prompt Decommissioning Approach for OPG's Nuclear Generating Stations." As shown on page 5 of the assessment, prompt decommissioning would increase the present value of the liability by approximately $500M for Pickering alone and by about $700M for all OPG nuclear stations, compared to OPG's planned deferred decommissioning strategy.

Prompt decommissioning (also known as immediate dismantling) is defined as the strategy in which the equipment, structures, components and parts of a facility containing radioactive material are removed or decontaminated to a level that permits the facility to be released for unrestricted use as soon as possible after permanent shutdown. The term "prompt" in the assessment refers to a safe storage duration of 11 years after station shut down. A period of 11 years for safe storage is required as used nuclear fuel removed from the core must cool in wet fuel bays for a minimum of 10 years in accordance with the licensed capability of OPG's dry storage containers established by the CNSC.

OPG's planned deferred decommissioning strategy is to shut down and store its nuclear generating stations in a safe state for nominally 30 years, followed by dismantlement, demolition, and site restoration.

Both the prompt decommissioning and deferred decommissioning scenarios are assumed to have the same staffing requirements. There is no ability to use operating staff to perform dismantlement work because different skill sets and unions are involved in these two activities.

OPG's assessment was based on costs reflected in a draft of the 2017 ONFA Reference Plan that were available at the time that the assessment was carried out in June, 2016. These costs may differ from those subsequently approved in the 2017 ONFA Reference Plan.

ONTARIO POWER GENERATION

Report

OPG Confidential	
Document Number: N-REP-00960-10006	Usage Classification: N/A
Sheet Number: N/A	Revision: R000

Title:

A PRELIMINARY ASSESSMENT TO DETERMINE THE FINANCIAL IMPACT OF USING A PROMPT DECOMMISSIONING APPROACH FOR OPG'S NUCLEAR GENERATING STATIONS

A Preliminary Assessment to Determine the Financial Impact of Using a Prompt Decommissioning Approach For OPG's Nuclear Generating Stations

2017 ONFA Based Update

N-REP-00960-10006-R000
2016-06-27

Order Number: N/A
Other Reference Number: N/A

OPG Confidential

Prepared by: J. Kennard, Section Manager, Cost Estimating, NWMO — 29/6/2016 Date

Reviewed by: V. Bostan, Section Manager, Nuclear Decommissioning Engineering, OPG — 29-06-2016 Date

Reviewed by: V. Seegobin, Manager, Decommissioning & Safstor Engineering, OPG — 29-Jun-16 Date

Approved by: J. Keto, Vice President, Nuclear Decommissioning, OPG — 29 June 2016 Date

Report	OPG Confidential		
	Document Number: N-REP-00960-10006		Usage Classification: N/A
	Sheet Number: N/A	Revision Number: R000	Page: 2 of 45

Title:

A PRELIMINARY ASSESSMENT TO DETERMINE THE FINANCIAL IMPACT OF USING A PROMPT DECOMMISSIONING APPROACH FOR OPG'S NUCLEAR GENERATING STATIONS

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A PRELIMINARY ASSESSMENT TO DETERMINE THE FINANCIAL IMPACT OF USING A PROMPT DECOMMISSIONING APPROACH FOR OPG'S NUCLEAR GENERATING STATIONS

Revision Summary

Revision Number	Date	Comments
R000	2016-06-27	Initial issue.

This report is an update of the original prompt decommissioning assessment report developed in 2013 following the 2012 ONFA update (N-REP-00960-10002-R000 December 2013). The baseline 30 year deferred decommissioning cost estimates used in this report are the draft April 2017 ONFA update station decommissioning cost estimates.

Executive Summary

Ontario Power Generation's (OPG's) planned deferred decommissioning strategy of its nuclear generating stations includes an assumed nominal 30 year safe storage period prior to the dismantling of station equipment and facilities. The Low and Intermediate Level Waste (L&ILW) produced during the safe storage and dismantling periods of the decommissioning is assumed to be emplaced in an appropriate long-term L&ILW Deep Geologic Repository (DGR).

Assessment Objective

In order to assess key decommissioning cost drivers a study was initiated by OPG's Nuclear Decommissioning group to determine the financial impact of varying safe storage periods.

All amounts quoted are in 2017$ unless otherwise indicated. The safe storage periods were varied and compared to the base 2017 ONFA reference case.

Impact of Prompt Scenario in Safe Storage Period

The study considered safe storage periods varying between 11[1] and 20 years to approximate *alternative* decommissioning scenarios. The term "prompt" in this report refers to a safe storage duration of 11 years.

When all OPG nuclear generating stations were considered, a reduction of the safe storage period from 30 to 11 years reduced the constant $ liability by 3.7% or $526M but increased the PV liability by 17% or $729M.

When only considering Pickering A&B stations, a reduction of the safe storage period from 30 to 11 years reduced the total constant $ liability by approximately 3% or $157M but increased the PV liability by 20% or $491M.

[1] A minimum ten year period is required to cool used fuel in the wet bays and one year will be required to transfer used fuel to dry storage.

Report

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Title:

A PRELIMINARY ASSESSMENT TO DETERMINE THE FINANCIAL IMPACT OF USING A PROMPT DECOMMISSIONING APPROACH FOR OPG'S NUCLEAR GENERATING STATIONS

NOTE

The objective of this study was to determine the financial impact of varying the decommissioning safe storage period on the total and Pickering only decommissioning liabilities. This study does not include impacts to the Used Fuel Storage, L&ILW Operations and L&ILW Long Term Disposal programs. As such the study makes no recommendation regarding an optimum decommissioning strategy or safe storage period.

The assumptions and dates used in this report are based on the draft April 2017 ONFA Reference Plan submitted to the Province in May, 2016 and may not reflect current planning assumptions and financial results.

1.0 STUDY OBJECTIVES

A major cost component of OPG's nuclear waste management and decommissioning liability is associated with the decommissioning of its nuclear generating stations. In order to evaluate OPG's deferred decommissioning strategy as compared to alternative prompt decommissioning strategies a decommissioning cost study was initiated by the Nuclear Decommissioning group at OPG.

The projected end of life of the Pickering nuclear generating stations in 2022/2024 identified the need to study the cost impact of accelerating the decommissioning of the Pickering generating stations; and the overall cost impact of a change in decommissioning strategy at all OPG nuclear generating stations.

The study was to address the effect of the reduction of the safe storage period and its associated change in constant $ and present value $. The reduction in the safe storage period was intended to approximate the impact of a prompt decommissioning approach.

TLG Services Inc, an external contractor who developed the 2017 ONFA Decommissioning cost estimates, was tasked with adjusting the cost estimates for different safe storage periods. TLG Services Inc, in conjunction with OPG, provided the high level technical assumptions necessary for the adjustment of the baseline cost estimates for these safe storage periods.

The NWMO was tasked with the integration and financial adjustment of the updated TLG cost estimates to complete the financial analysis.

This report summarizes the study findings, including the cost implications of the strategies considered to accelerate the decommissioning process to approximate an 11 year and 20 year safe storage period. The term "prompt" in this report refers to safe storage duration of 11 years.

2.0 BACKGROUND

Ontario Power Generation's (OPG) planned approach to the decommissioning of its nuclear generating stations is based on a nominal 30 year deferred decommissioning strategy. This multi-stage approach includes the disposition of L&ILW resulting from the decontamination and dismantling of the facilities in a L&ILW DGR [R-1]. The funding of the decommissioning of the nuclear generating stations is regulated by the Ontario Nuclear Funds Agreement (ONFA). Under the agreement, the decommissioning liability is updated on a five year cycle. The required funding to complete the decommissioning is accumulated within the operating lives of the nuclear generating stations. The recent 2017 ONFA Reference Plan update of the estimated decommissioning liability was based on the projected end of life dates shown in Table 1 using the nominal 30 year deferred decommissioning strategy [R-1].

Table 1: Station Planning Assumptions

Station/Unit	Unit In-Service Date	2017 ONFA (30 year deferred)		
		End of Life	Dismantling Date	Site Restoration Complete
Pickering A – Unit 1	Jul, 1971	2022	2051	2064
Pickering A – Unit 2/3	Dec, 1971 Jun, 1972	2005	2052/53	
Pickering A – Unit 4	Jun, 1973	2022	2054	
Pickering B – Unit 5	May, 1983	2024	2055	2065
Pickering B – Unit 6	Feb, 1984	2024	2056	
Pickering B – Unit 7	Jan, 1985	2024	2057	
Pickering B – Unit 8	Feb, 1986	2024	2058	
Darlington – Unit 1	Nov, 1992	2053	2084	2093
Darlington – Unit 2	Oct, 1990	2049	2085	
Darlington – Unit 3	Feb, 1993	2052	2086	
Darlington – Unit 4	Jun, 1993	2055	2087	
Bruce A – Unit 1	Sep, 1977	2043	2086	2095
Bruce A – Unit 2	Sep, 1977	2043	2087	
Bruce A – Unit 3	Feb, 1978	2061	2088	
Bruce A – Unit 4	Jan, 1979	2062	2089	
Bruce B – Unit 5	Mar, 1985	2061	2090	2099
Bruce B – Unit 6	Sep, 1984	2057	2091	
Bruce B – Unit 7	Apr, 1986	2063	2092	
Bruce B – Unit 8	May, 1987	2063	2093	

The 2017 ONFA update included cost estimates for all OPG owned nuclear generating stations and waste management facilities which form the most significant portion of the decommissioning liability. The decommissioning cost estimates were prepared by TLG Services Inc. The basis of the cost estimates, including comparisons to the previous cost estimates, is detailed in the station decommissioning cost study reports and comparison reports prepared by TLG [R-3 to R-10].

The cost estimates include updates to both economic and technical assumptions. The economic update reflects current conditions and costs in 2015 dollars (i.e. disposal, labor, insurance, regulatory agency fees, property taxes, and energy costs). The technical update reflects current industry practice and experience in the United States. Decommissioning cost estimate summary details can be found in the “2017 ONFA Reference Plan Update Decommissioning Summary Cost Estimate Report” [R-11].

Table 2 details the estimated costs to decommission the OPG nuclear generating stations stated in 2015 constant M$.

Table 2: 2017 ONFA Station Decommissioning Liabilities – Detail (2015 Constant k$)

Work Breakdown Structure	Bruce A	Bruce B	Pickering A	Pickering B	Darlington	Total	% of CTD*
DGR EXPENSES	**$ 108,160**	**$ 113,217**	**$ 126,239**	**$ 108,855**	**$ 175,673**	$ 632,144	**4.8%**
DGR Excavation (Years 2039 thru 2043)	$ 79,196	$ 82,899	$ 92,434	$ 79,705	$ 128,630	$ 462,864	3.6%
DGR Decommissioning (2100 thru 2104)	$ 28,964	$ 30,318	$ 33,805	$ 29,150	$ 47,043	$ 169,281	1.3%
MANAGEMENT OF HEAVY WATER	**$ 34,067**	**$ 34,067**	**$ 9,280**	**$ 9,280**	**$ 38,766**	**$ 125,460**	**1.0%**
PREPARATION FOR SAFE STORAGE	**$ 348,060**	**$ 353,078**	**$ 392,040**	**$ 517,300**	**$ 586,575**	**$ 2,197,053**	**16.9%**
Defueling	$ -	$ -	$ 4,571	$ 9,149	$ 10,257	$ 23,977	0.2%
Preparation and Implementation	$ 72,919	$ 76,262	$ 16,172	$ 90,423	$ 95,735	$ 351,510	2.7%
Engineering and Planning	$ 2,500	$ 2,500	$ -	$ 2,500	$ 2,500	$ 10,000	0.1%
Decontamination of Systems/Structures	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Decontamination Equipment and Supplies	$ 121	$ 121	$ 601	$ 198	$ 120	$ 1,161	0.0%
Health Physics Equipment and Supplies	$ 4,179	$ 4,179	$ 7,683	$ 7,962	$ 4,891	$ 28,895	0.2%
Dismantling Equipment and Tooling	$ 15	$ 15	$ 11	$ 18	$ 17	$ 75	0.0%
Waste Processing	$ 24,697	$ 24,697	$ 2,061	$ 5,564	$ 17,477	$ 74,496	0.6%
Energy	$ 17,665	$ 18,310	$ 59,418	$ 48,896	$ 24,401	$ 168,690	1.3%
Insurance, Fees and Taxes	$ 12,541	$ 13,570	$ 29,387	$ 47,850	$ 41,244	$ 144,592	1.1%
Staffing	$ 183,173	$ 183,173	$ 222,625	$ 242,800	$ 308,439	$ 1,140,210	8.7%
Overhead Costs	$ 30,251	$ 30,251	$ 49,511	$ 61,941	$ 81,492	$ 253,446	1.9%
SAFE STORAGE	**$ 312,071**	**$ 391,061**	**$ 474,341**	**$ 437,863**	**$ 554,834**	**$ 2,170,169**	**16.6%**
Facility Maintenance	$ 31,093	$ 36,501	$ 37,056	$ 36,553	$ 46,271	$ 187,474	1.4%
Health Physics Supplies	$ 11,288	$ 13,444	$ 14,027	$ 14,874	$ 17,285	$ 70,918	0.5%
Waste Processing	$ 5,892	$ 6,152	$ 1,110	$ 5,498	$ 8,679	$ 27,331	0.2%
Energy	$ 45,737	$ 54,689	$ 88,073	$ 79,110	$ 65,837	$ 333,447	2.6%
Insurance, Fees and Taxes	$ 98,109	$ 137,825	$ 164,088	$ 146,175	$ 247,010	$ 793,208	6.1%
Staffing	$ 79,133	$ 94,356	$ 122,648	$ 74,932	$ 112,246	$ 483,316	3.7%
Overhead Costs	$ 40,817	$ 48,094	$ 47,338	$ 50,225	$ 57,505	$ 243,980	1.9%
Heavy Water Storage (Pickering Only)	$ -	$ -	$ -	$ 30,496	$ -	$ 30,496	0.2%
PREPARATIONS FOR DISMANTLING	**$ 189,526**	**$ 171,786**	**$ 163,103**	**$ 172,417**	**$ 192,102**	**$ 888,933**	**6.8%**
Preparations	$ 65,353	$ 56,642	$ 58,041	$ 59,614	$ 65,448	$ 305,098	2.3%
Engineering and Planning	$ 28,721	$ 18,813	$ 25,493	$ 28,297	$ 28,721	$ 130,044	1.0%
Health Physics Supplies	$ 2,402	$ 2,402	$ 2,049	$ 2,350	$ 2,401	$ 11,603	0.1%
Dismantling Equipment and Tooling	$ 3,059	$ 3,059	$ 2,890	$ 3,398	$ 3,398	$ 15,806	0.1%
Waste Processing	$ 305	$ 305	$ 185	$ 210	$ 331	$ 1,336	0.0%
Energy	$ 12,457	$ 12,457	$ 7,949	$ 9,346	$ 11,967	$ 54,177	0.4%
Insurance, Fees and Taxes	$ 4,592	$ 5,473	$ 4,563	$ 5,169	$ 7,324	$ 27,121	0.2%
Staffing	$ 65,495	$ 65,495	$ 56,883	$ 57,392	$ 65,463	$ 310,728	2.4%
Overhead Costs	$ 7,142	$ 7,139	$ 5,049	$ 6,641	$ 7,048	$ 33,020	0.3%
DISMANTLING	**$ 1,136,936**	**$1,150,607**	**$ 1,153,211**	**$ 1,043,867**	**$1,415,009**	**$ 5,899,630**	**45.3%**
Preparations	$ 62,232	$ 60,118	$ 92,190	$ 44,503	$ 90,078	$ 349,121	2.7%
PHT and Moderator System Removal	$ 365,286	$ 368,754	$ 334,444	$ 308,980	$ 458,670	$ 1,836,134	14.1%
Disposal of Plant Systems	$ 111,792	$ 111,792	$ 107,047	$ 131,484	$ 298,947	$ 761,063	5.8%
Decontamination of Site Buildings	$ 50,455	$ 56,546	$ 69,089	$ 30,395	$ 59,065	$ 265,550	2.0%
Final Survey	$ 61,568	$ 61,009	$ 47,825	$ 47,450	$ 61,644	$ 279,496	2.1%
Decontamination Equipment and Supplies	$ 13,130	$ 12,861	$ 13,278	$ 14,658	$ 18,371	$ 72,298	0.6%

Health Physics Supplies	$ 35,695	$ 35,575	$ 31,221	$ 30,637	$ 42,899	$ 176,026	1.4%
Dismantling Equipment and Tooling	$ 42,191	$ 42,382	$ 45,996	$ 47,165	$ 39,878	$ 217,612	1.7%
Waste Processing	$ 16,360	$ 16,268	$ 12,139	$ 12,503	$ 18,752	$ 76,023	0.6%
Energy	$ 32,546	$ 32,682	$ 25,467	$ 24,468	$ 25,007	$ 140,171	1.1%
Insurance, Fees and Taxes	$ 22,078	$ 27,731	$ 38,023	$ 21,902	$ 23,294	$ 133,028	1.0%
Staffing	$ 274,849	$ 276,176	$ 281,418	$ 283,604	$ 226,172	$ 1,342,219	10.3%
Overhead Costs	$ 48,755	$ 48,712	$ 55,075	$ 46,117	$ 52,231	$ 250,890	1.9%
SITE RESTORATION	**$ 248,850**	**$ 257,599**	**$ 170,438**	**$ 137,621**	**$ 306,223**	**$ 1,120,731**	**8.6%**
Demolition of Remaining Site Buildings	$ 87,179	$ 91,213	$ 64,519	$ 88,164	$ 181,813	$ 512,888	3.9%
Site Closeout	$ 60,685	$ 60,665	$ 1,926	$ 1,303	$ 2,583	$ 127,162	1.0%
Dismantling Equipment and Tooling	$ 33,786	$ 33,850	$ 37,584	$ 1,005	$ 36,123	$ 142,348	1.1%
Energy	$ 2,919	$ 3,020	$ 2,212	$ 2,567	$ 3,602	$ 14,319	0.1%
Insurance, Fees and Taxes	$ 11,588	$ 15,181	$ 12,224	$ 14,187	$ 18,765	$ 71,944	0.6%
Staffing	$ 38,322	$ 38,806	$ 39,548	$ 16,644	$ 40,625	$ 173,945	1.3%
Overhead Costs	$ 14,372	$ 14,865	$ 12,426	$ 13,750	$ 22,711	$ 78,124	0.6%
Total Cost To Decommission (CTD*)	**$ 2,377,670**	**$2,471,415**	**$ 2,488,651**	**$ 2,427,204**	**$3,269,180**	**$ 13,034,121**	**100.0%**
Risk Contingency (4%)	**$ 95,107**	**$ 98,857**	**$ 99,546**	**$ 97,088**	**$ 130,767**	**$ 521,365**	
Total Cost With Risk Contingency	**$ 2,472,777**	**$2,570,272**	**$ 2,588,197**	**$ 2,524,292**	**$3,399,947**	**$ 13,555,485**	

Table 3 provides the total estimated cost to decommission the generating stations in 2015 constant M$, and for the 2017 ONFA reference plan update period from 2017 forward in 2017 constant M$.

Table 3: 2017 ONFA Station Decommissioning Liabilities – Total

Generating Station	TLG 2015 / 2016 Estimates 2015 constant M$ (2015 forward)	2017 ONFA Reference Plan Update 2017 constant M$ (2017 forward)
Pickering A	2,588	2,660
Pickering B	2,524	2,604
Bruce A	2,473	2,573
Bruce B	2,570	2,674
Darlington	3,400	3,535
Total	13,555	14,045

For 2017 ONFA, oversight costs specific to the OPG decommissioning program were not included in the TLG Services cost estimates but rather estimated separately by OPG. These costs include oversight by the OPG Nuclear Decommissioning Division and the NWMO. Details regarding the oversight costs are found in "2017 ONFA Reference Plan Update Operational Oversight Cost Estimate Report" [R-13]. For 2017 ONFA a heavy water management cost was included for each station within the station cost estimates prepared by TLG Services.

The total decommissioning cost for all OPG nuclear generating stations including Decommissioning Oversight for all OPG stations is shown in Table 4.

Table 4: 2017 ONFA Station Decommissioning Liability Including Oversight and Heavy Water Management

Activity	2017 ONFA Reference Plan Update 2017 constant M$ (2017 forward)
Station Decommissioning	14,045
Decommissioning Oversight*	110
Total Decommissioning Cost	14,155
Total (2017 PV M$)	4,140

* Cost allocated equally to all OPG nuclear station units.

3.0 DECOMMISSIONING STRATEGY SELECTION

The approaches available for the decommissioning of nuclear generating stations are well documented in the nuclear industry. A detailed description of common decommissioning approaches is beyond the intended scope of this study; however a brief overview of the approaches will provide some context to OPG's currently selected strategy.

3.1 Decommissioning Approaches

There are four principle approaches to the decommissioning of nuclear generating stations and additional variations which combine features of the three.

The four principle approaches are [R-15]:

(1) Prompt Decommissioning – Also known as Immediate Dismantling
(2) Deferred Dismantling – Also known as Deferred Decommissioning
(3) Entombment
(4) Hybrid

3.1.1 Prompt Decommissioning

Prompt decommissioning is the strategy in which the equipment, structures, components and parts of a facility containing radioactive material are removed or decontaminated to a level that permits the facility to be released for unrestricted use as soon as possible after permanent shutdown. In this study this approach will be compared to the deferred decommissioning approach.

3.1.2 Deferred Decommissioning

Deferred decommissioning is the strategy in which the final dismantling of the facility is delayed and the facility is placed into long-term storage where it is maintained in a safe condition. This strategy may involve some initial decontamination or dismantling, but a major part of the facility will remain for a certain time period. This time period might range from a few years to 50 years, after which time the decommissioning process will be completed and the facility released from regulatory control.

The deferred approach is the currently selected OPG decommissioning strategy.

3.1.3 Entombment

Entombment is the strategy in which the radioactive contaminants are encased in a structurally long lasting material until the radioactivity decays to a level that permits release of the facility from regulatory control. While the entombment option is a recognized option by the CNSC, and is in use in some parts of the world, it is not an approach which OPG considers appropriate for use at its sites to date and will thus not be discussed further within this report.

3.1.4 Hybrid

Hybrid decommissioning is the strategy in which decommissioning proceeds according to a sequence of dismantling activities and periods of safe storage or entombment according to prevailing conditions e.g. resource availability, safety, environmental and stakeholder conditions. An assessment of hybrid options could be undertaken at a future date. Such an assessment would be complex and involve a significant technical component in assessing hybrid scenarios.

3.2 Factors Affecting Strategy Selection

The selection of a decommissioning strategy is dependent on a number of factors which a utility must consider. The Table 5 lists typical key factors which may be considered in the selection.

Table 5: Typical Factors Affecting Decommissioning Strategy Selection

Factor	Description
1	Health and safety
2	Regulatory
3	Funding approach
4	Adequacy of funding
5	Availability of interim waste storage facilities (L&ILW)
6	Availability of long-term waste management facilities (L&ILW and used fuel)
7	Cost of decommissioning L&ILW waste management
8	Expected end use/condition of site
9	Availability of technology
10	Availability of trained personnel
11	Used fuel options/implications
12	Economies of scale for multi-unit installations
13	Operating station staff transition plan
14	Multi-unit station operational implications

The key factors are typically re-classified as “pros” or “cons” when making the decommissioning strategy decision as shown in Table 6 for Prompt versus Deferred decommissioning.

Table 6: Pros and Cons of Prompt Versus Deferred Decommissioning

Strategy	Pro	Con
Prompt Decommissioning	• Land is available earlier for redevelopment • More knowledge retention during decommissioning • Lower constant dollar due to shorter safe storage period (less upkeep) • Socially most acceptable	• More dose exposure to workers • Higher PV costs • Unavailability of a L&ILW disposal facility (PNG only) • More intermediate level waste and less free release waste due to decay • Unavailability of a used fuel disposal facility (PNG only)
Deferred Decommissioning	• Allows for continued growth of decommissioning fund • Less dose exposure to workers • Less intermediate level waste and more free release waste due to decay • Potential for reduced dismantling costs due to advances in technology • A L&ILW DGR to accept decommissioning waste would be available • Lower PV costs	• Less knowledge retention during decommissioning • Higher constant dollar cost due to a longer safe storage period (more upkeep)

4.0 DECOMMISSIONING AT OPG

4.1 Rationale for Deferred Decommissioning Strategy

OPG is obligated to meet the requirements of the Canadian Nuclear Safety and Control Act with regard to the operation and decommissioning of its nuclear generating stations. Under the Act, OPG must provide a financial guarantee (CNSC Financial Guarantee) for the eventual decommissioning of its nuclear generating stations and other Class I facilities. (e.g. waste management facilities)

The CNSC Financial Guarantee needs to meet the requirements of Regulatory Guides G-206 and G-219 published by the CNSC ([R-16] to [R-17]) and CSA N294-09 [R-18].

G-219, titled “Decommissioning Planning for Licensed Facilities”, requires that Preliminary Decommissioning Plans (PDPs) be prepared in support of station licenses and financial guarantees. The PDPs submitted to the CNSC identify the overall approach to the decommissioning of the facilities including the planned decommissioning strategy.

OPG’s current strategy for decommissioning is to shut down and store its nuclear generating stations in a safe state for nominally 30 years (referred to as “Deferred Decommissioning”), followed by dismantlement, demolition, and site restoration. The duration of the Safe Storage period was determined by balancing the reduced decommissioning cost and occupational dose against the increased social and economic costs of a longer storage period.

OPG has chosen a *30 year deferred decommissioning strategy* decommissioning strategy that is considered to minimize both the occupational radiation dose to staff and the potential exposure to the public and the environment. OPG has identified this approach within the PDPs as its planned approach since the inception of its nuclear program.

The “Deferred Dismantling” strategy for decommissioning of OPG’s nuclear plants was chosen based on detailed consideration of the following:

Radiation Protection

- Avoids dose/radiation exposure – Dismantling the radioactive parts of the nuclear stations are considered to be the most challenging, and labour and cost intensive activities involved in decommissioning. Hence, reducing the amount of radiation exposure to workers, public and the environment was one of the most important factors considered when OPG was developing the strategy for decommissioning. The 30 year deferral approach reduces the potential dosage through the natural decay of radionuclides and is consistent with the As Low As Reasonably Achievable (ALARA) principle.

Waste Management

- Deferred decommissioning allows time to implement the long-term L&ILW strategy – OPG plans to place L&ILW generated during decommissioning (for Pickering or other facilities) in the L&ILW DGR located in Kincardine.

- Deferred decommissioning allows time to implement the Used Fuel disposal repository – OPG currently assumes that a long-term used fuel management facility will be in-service in 2043. While OPG's current approach for selected generating stations is to accelerate the transfer of used fuel from wet-bays to dry storage, it is assumed that the remaining stations will move fuel directly from the wet-bays to the facility starting in 2043. This will impact the ability of some stations to decommission promptly if required.

- Wet-bay limit on fuel movement – When used fuel is removed from OPG reactors, it must remain in the station wet-bays for a period of approximately 10 years to cool before transfer to dry storage. This limits all stations to a minimum 11 year deferral period on decommissioning. (1 additional year for emptying the wet bays.)

- Reduced disposal cost for waste – In addition to the dismantling and radioactive exposure reasons cited in item 1, the deferred approach will reduce the volume of ILW produced since it would decay to LLW and hence the associated cost of disposal. Also some LLW (such as contaminated soil) would decay to a point which it could be free released.

- Multi-Unit station advantage – The deferred dismantling approach is often used at multi-unit stations when one or more of the units are shutdown while others continue to operate (e.g. Pickering). This is especially true of stations which share some common systems (all OPG stations).

Financial

- Funding – The funding required for the decommissioning of nuclear generating stations is accumulated over the operating lives of the stations. Funding levels are based on the present value of future costs.

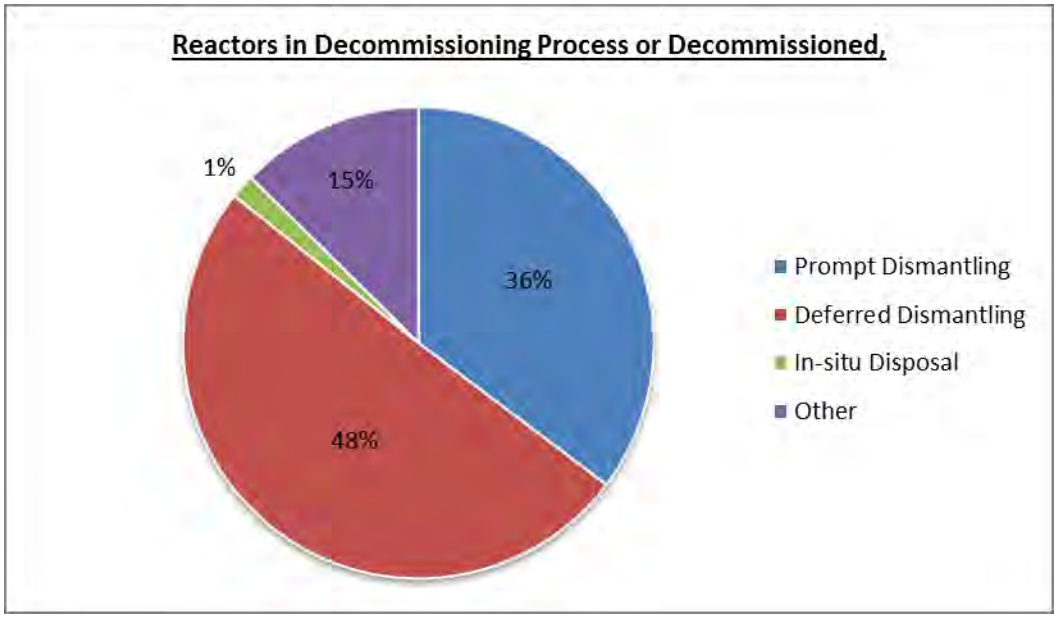
- Potential for reduced costs – Dismantling costs may decline in the future with the advent of new technologies and use of industry operating experience.

International Experience

- As of December 2015, 157 power reactors worldwide had been permanently shut down. Of these, 34 power reactors had been fully decommissioned and licences terminated. Of the remaining 123 power reactors:

  - 59 opted for deferred dismantling
  - 44 opted for prompt dismantling
  - 2 opted for in-situ disposal
  - 18 had not commenced decommissioning and/or did not have a specified strategy

Figure 1: International Decommissioning Experience



4.2 Periodic Review of OPG Decommissioning Strategy

OPG's decommissioning strategy has historically been reviewed on a five year cycle; typically aligned with ONFA reference plan update [R-19]. OPG reviews the decommissioning strategy internally during the regular review process of planning assumptions for the ONFA Reference plan update. The most recent internal review was completed in 2016 at the time of the 2017 ONFA reference plan update. OPG also reviews all decommissioning assumptions on a yearly basis to determine if any changes are required. Specific to Pickering, a report was completed in 2015 to present the rationale for selecting OPG's 30 year deferred decommissioning strategy [R-21].

4.3 Benchmarking of OPG Decommissioning Cost Estimates

OPG's decommissioning strategy and costs are often benchmarked against industry practice. In 2012 OPG contracted with an external consultant to benchmark its current (2011) decommissioning cost estimates against industry practice and results [R-20]. The benchmarking study concluded that OPG's cost estimates are of a similar order of magnitude with other facilities similar in nature, location and size. The study also concluded that OPG's decommissioning cost projections are in line with industry practice The methodology used to benchmark OPG's cost estimates was based on converting all available data into the IAEA's International Structure for Decommissioning Costs (ISDC) structure so to allow for direct comparison and analysis.

4.4 OPG Decommissioning Process

The current OPG deferred decommissioning process is detailed in Appendix H. The process, including the staged activities, is used to form the basis of the OPG station decommissioning cost estimates.

In industry practice, *Safe Storage* is generally defined as "the strategy in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."

The staged activities meet or exceed the requirements of G-206, G-219, and CSA N294-09 regarding nuclear generating station decommissioning.

The decommissioning stages included within each nuclear generating station cost estimate include:

- Stage 1 - Preparation for Safe Storage
- Stage 2 - Safe Storage
- Stage 3A - Preparation for Dismantling
- Stage 3B - Dismantling
- Stage 3C - Site Restoration

5.0 ASSUMPTIONS

The sections below describe the assumptions used to develop the various scenarios and to perform the analysis.

5.1 Safe Storage Scenarios and Assumptions

A principle objective of the cost study was to address the effect of the reduction of the safe storage period and its associated change in the constant $ and PV $ projected for the decommissioning of the nuclear generating stations. The reduction in the safe storage period is intended to approximate the impact of a prompt decommissioning approach.

The OPG reference case scenario includes a nominal 30 year safe storage period following the shutdown of the last unit in a given four unit station. To achieve reductions in the 30 year safe storage period, the baseline 2017 ONFA cost estimates were adjusted by TLG Services for the changes in safe storage periods at a macro level. For each scenario the specific changes to the cost estimate assumptions are provided in the appendices.

Appendices B to G of this document provide details for two additional scenarios intended to address a range of reasonable deferral periods. The scenarios include 11 year and 20 year safe storage periods.

For each scenario the appendices detail:

(1) The deferral dates for the start of dismantling and the completion of site restoration for the specific scenario. (All scenarios use the same shutdown dates as in the case of the 2017 ONFA reference plan.)
(2) The assumptions applied to the 2017 ONFA decommissioning cost estimates to adjust the safe storage period.
(3) The constant dollar and present value dollar liabilityfor the specific scenario.

Table 7 shows the high level assumptions applied to the decommissioning cost estimate scenarios in the form of adjustments to approximate the impact of the adjusted safe storage periods.

The scenario results are summarized in Section 6.0 of this document.

5.2 Unquantified Factors

In developing the adjustments to the 30 year deferred baseline cost estimates for the 11 and 20 year scenario cases a number of factors were identified which could not be cost quantified without a more detailed analysis. These included the following:

(1) More decontamination required during Dismantling (less decay) as compared to 30 year scenario.
(2) An increase in Work Difficult Factors during Dismantling due to less decay as compared to 30 year scenario.
(3) The impact of having Used Fuel on site post site-restoration for PNGS. (applicable for 11-year scenario)
(4) Reduce staff turnover thereby reducing hiring and training (applicable for 11-year scenario)
(5) Safe-Storage project and plant experience maintained reducing the amount of knowledge transfer required (applicable for 11-year scenario)
(6) Mitigation of the risk of records/documents being lost of unavailable during dismantling (applicable for 11-year scenario)
(7) Activities required to revise the DGR Operational Licence for emplacement of decommissioning waste as well as the risk of not getting the necessary approvals from the CNSC.

Table 7: Deferral Scenario Assumptions

Item	11-Year Scenario	20-Year Scenario
1	Shut down dates remain unchanged as compared to 30 year scenario.	Shut down dates remain unchanged as compared to 30 year scenario.
2	The safe-storage dormancy durations were reduced such that "Preparations for Dismantling" start immediately after all spent fuel has been removed from the spent fuel storage bays 11 years after station shutdown. (10 years cooling of fuel in wet bays and 1 year for fuel removal from wet bays.) Durations for Dismantling and Site Restoration remains unchanged as compared to 30 year scenario.	The safe-storage dormancy durations were reduced such that "Preparations for Dismantling" start 20 years after station shutdown. Durations for Dismantling and Site Restoration remains unchanged as compared to 30 year scenario.
3	Sequence of "unit" dismantling remains unchanged as compared to 30 year scenario.	Sequence of "unit" dismantling remains unchanged as compared to 30 year scenario.
4	The "starting" cash flows utilized for the Bruce Stations reflect the OPG Post Turnover Station Responsibility costs.	The "starting" cash flows utilized for the Bruce Stations reflect the OPG Post Turnover Station Responsibility costs.
5	Include cost of PHT flush in Prep for Safe-Storage. Note: TLG to use escalated costs from the 2012 Cost Estimate.	Include cost of PHT flush in Prep for Safe-Storage. Note: TLG to use escalated costs from the 2012 Cost Estimate.
6	Increase ILW containers by 25% as compared to 30 year scenario.	Increase ILW containers by 10% as compared to 30 year scenario.
7	Increase volume of Calandria Vault concrete in Pickering A by 10% as compared to 30 year scenario.	Increase volume of Calandria Vault concrete in Pickering A by 5% as compared to 30 year scenario.
8	Include $200M (includes contingency) for an additional Interim Storage facility required to store Pickering Heavy Water. Note 1: The cost will incur during the 2 years prior to Preparation for Dismantling. Note 2: The cost for transportation is assumed to be included in the $200M.	Include $200M (includes contingency) for an additional Interim Storage facility required to store Pickering Heavy Water. Note: The cost will incur during the 2 years prior to Preparation for Dismantling. Note 2: The cost for transportation is assumed to be included in the $200M.
9	Interim Heavy Water Storage yearly energy cost and operational and maintenance cost remains unchanged as compared to the 30 year scenario (i.e. $50K/year for heating for 5 years per station and $1.1M/year for operations and maintenance from 2023-2050 for PNGS)	Interim Heavy Water Storage yearly energy cost and operational and maintenance cost remains unchanged as compared to the 30 year scenario (i.e. $50K/year for heating for 5 years and $1.1M/year for operations and maintenance from 2023-2050 for PNGS)

10	DGR Decommissioning timeline stays the same as compared to 30 year scenario. (2100-2105)	DGR Decommissioning timeline stays the same as compared to 30 year scenario. (2100-2105)
11	Stage 3 (Prep for Dismantling) Assumptions 1. Site Characterization – No change as compared to 30 year scenario. 2. Review and Revise Plant Dwgs & Specs – 50% reduction as compared to 30 year scenario. 3. Define Major Work Sequence – No change as compared to 30 year scenario. 4. Perform Site-specific Cost Analysis – No change as compared to 30 year scenario. 5. Prepare and Submit License Termination Plan – No change as compared to 30 year scenario.	Stage 3 (Prep for Dismantling) Assumptions 1. Site Characterization – No change as compared to 30 year scenario. 2. Review and Revise Plant Dwgs & Specs – No change as compared to 30 year scenario. 3. Define Major Work Sequence – No change as compared to 30 year scenario. 4. Perform Site-specific Cost Analysis – No change as compared to 30 year scenario. 5. Prepare and Submit License Termination Plan – No change as compared to 30 year scenario.
12	No impact to Preparation for Safe-Storage activities as compared to 30 year scenario. (e.g., heating, staffing, plant modifications, etc.)	No impact to Preparation for Safe-Storage activities as compared to 30 year scenario. (e.g., heating, staffing, plant modifications, etc.)
13	No change to Environmental Assessment costs during Stage 3 as compared to 30 year scenario.	No change to Environmental Assessment costs during Stage 3 as compared to 30 year scenario.
14	Pickering A – Units 2 and 3 have already completed Stage 1 resulting in a 20+ years difference between Stage 1 and Stage 3. No adjustments were made to the two units as compared to 30 year scenario (except for the revised safe-storage duration).	Pickering A – Units 2 and 3 have already completed Stage 1 resulting in a 20+ years difference between Stage 1 and Stage 3. No adjustments were made to the two units as compared to 30 year scenario (except for the revised safe-storage duration).

6.0 STUDY RESULTS

6.1 Safe Storage Period Impact (Deferred vs. Prompt Decommissioning)

OPG's deferred decommissioning strategy is sub-divided into a number of phases. These include Preparation for Safe Storage, Safe Storage, Preparation for Dismantling, Dismantling, and Site Restoration. The *safe storage* period extends for a nominal 30 years following the shutdown of the final unit of an OPG multi-unit station. A minimum safe storage period of 11 years is required to allow used fuel to cool sufficiently for 10 years before being transferred to dry storage containers for interim storage on-site which takes approximately 1 year.

The cost study considered safe storage periods varying between 11 and 20 years to approximate *alternative* decommissioning scenarios.

Table 8 illustrates the high level impact of varying the safe storage period from the OPG planned 30 year period. Results for safe storage periods of 11 years and 20 years are detailed in the table.

In total, for all OPG nuclear generating stations, a reduction of the safe storage period from 30 to 11 years reduces the constant $ liability by 3.7% or $526M but increases the PV by 17% or $729M.

To achieve the reduction to 11 years, the reference base cost estimate was adjusted such that "preparation for dismantling" activities were accelerated. Refer to Appendix B for details.

In the case of Pickering A and B, a reduction of the safe storage period from 30 to 11 years reduces the total constant $ liability by approximately 3% or $157M but increases the PV liability by 20% or $491M.

For comparative purposes the base case 2017 ONFA decommissioning costs were compared to the adjusted costs for each safe storage period. Under ONFA, OPG assumes that the Bruce A and B station decommissioning costs are offset by the conditions of the Bruce Lease between OPG and Bruce Power. Under the lease, both Bruce A and Bruce B will be returned (turned-over) to OPG at the same time to continue safe storage and for decommissioning in 2065. Using 2017 ONFA planning assumptions, prior to the turn-over date, safe storage costs for Bruce A and Bruce B units which shut down prior to this date will be incurred by Bruce Power.

Table 8: Impact of Variation in Deferred Decommissioning Periods

	Station	Shutdown*	2017 ONFA**	11 Yr Deferred		20 Yr Deferred	
			Cost	Cost	% Change	Cost	% Change
2017 Constant K$ (2017 Forward)	Pickering A	2022	$ 2,692,724	$ 2,479,530	-7.92%	$ 2,495,405	-7.3%
	Pickering B	2024	$ 2,626,841	$ 2,683,006	2.14%	$ 2,690,427	2.4%
	Bruce A	2062	$ 2,572,689	$ 2,446,526	-4.90%	$ 2,570,918	-0.1%
	Bruce B	2063	$ 2,673,876	$ 2,600,301	-2.75%	$ 2,687,295	0.5%
	Darlington	2055	$ 3,534,936	$ 3,366,178	-4.77%	$ 3,477,976	-1.6%
	Total		$ 14,101,067	$ 13,575,541	-3.73%	$ 13,922,023	-1.3%

	Station	Shutdown*	2017 ONFA**	11 Yr Deferred		20 Yr Deferred	
			Cost	Cost	% Change	Cost	% Change
2017 PV K$ (2017 Forward)	Pickering A	2022	$ 1,255,877	$ 1,438,172	14.5%	$ 1,289,030	2.6%
	Pickering B	2024	$ 1,213,645	$ 1,522,543	25.5%	$ 1,387,863	14.4%
	Bruce A	2062	$ 514,458	$ 568,750	10.6%	$ 527,062	2.5%
	Bruce B	2063	$ 507,882	$ 565,635	11.4%	$ 521,485	2.7%
	Darlington	2055	$ 807,641	$ 933,280	15.6%	$ 821,567	1.7%
	Total		$ 4,299,502	$ 5,028,379	16.95%	$ 4,547,007	5.8%

* last station unit per 2017 ONFA

** 30 year deferred 2017 forward before OPG oversight

Figures 2 to 4 illustrate the impact of the variation in the safe storage (deferral) period for OPG nuclear generating stations individually and in total.

Figure 2: Station Decommissioning Cost (Constant$)

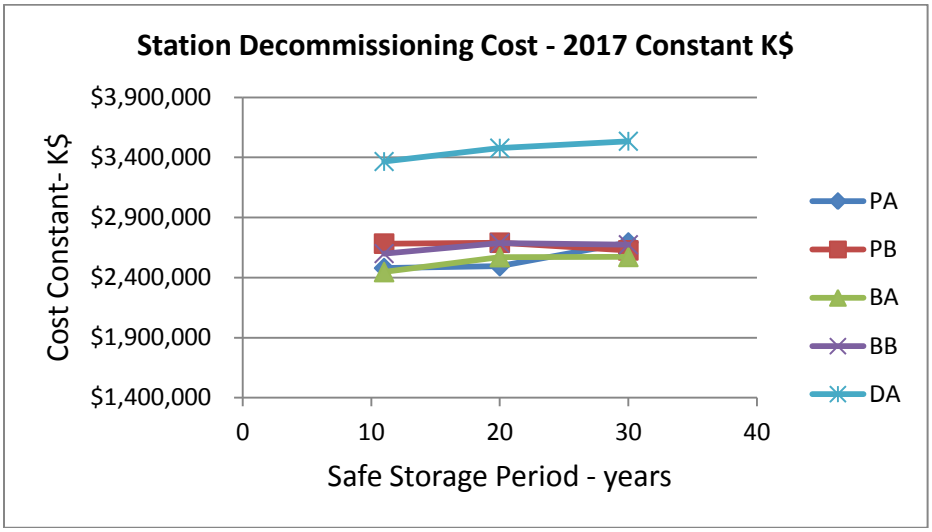


Figure 3: Station Decommissioning Cost (PV$)

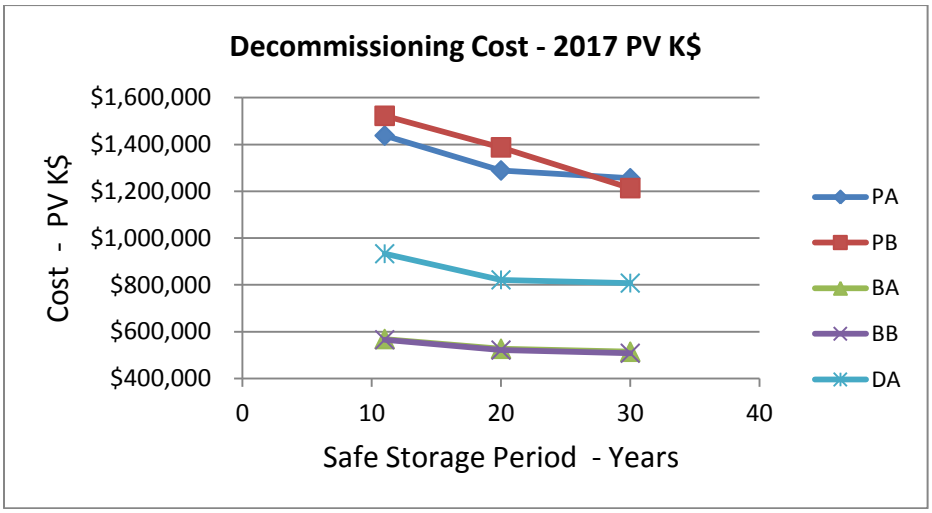
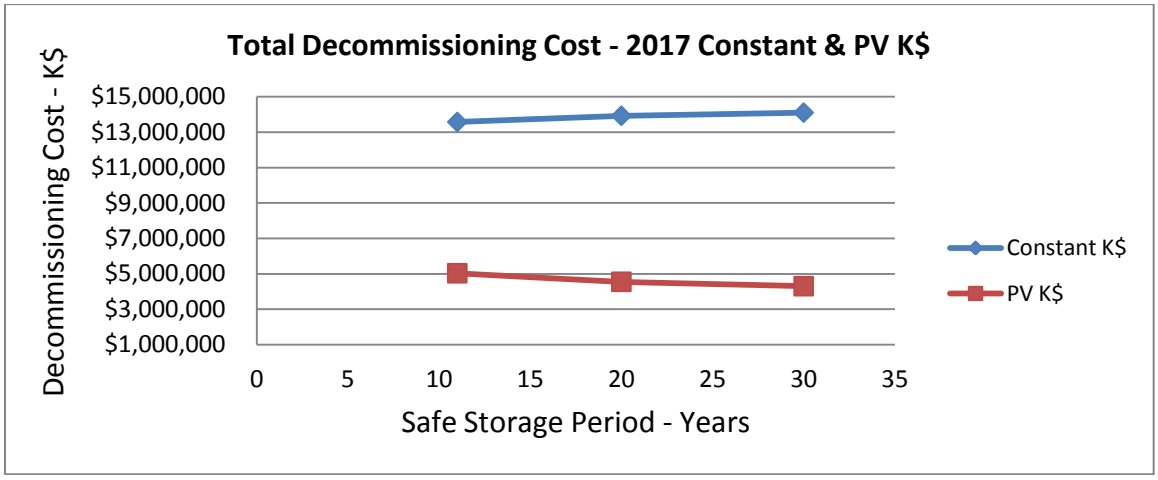


Figure 4: Total Decommissioning Cost All Stations



Refer to Appendices D and G for further details.

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Appendix A: 2017 Decommissioning Waste Volumes

2017 Decommissioning Waste Volumes (M3)			
Facility	**LLW**	**ILW**	**LLW+ILW**
Darlington	47,042	3,572	50,614
Pickering A	33,509	2,864	36,373
Pickering B	28,483	2,890	31,373
Bruce A	27,692	3,479	31,171
Bruce B	29,057	3,566	32,623
Total Stations	**165,783**	**16,371**	**182,154**
Pickering WMF	191		
Darlington WMF	123		
WWMF	4,947		
RWOS1 & CMLF	1,199		
Total WMFs	**6,460**		
Grand Total	**172,243**	**16,371**	**188,614**

Appendix B: 11 Year Prompt Decommissioning Dates

Station/Unit	Unit In-Service Date	2017 ONFA (30 year deferred)			2017 Prompt (11yr deferred)	
		End of Life	Dism.	Site Rest. Complete	Dism.	Site Rest. Complete
Pickering A – Unit 1	Jul, 1971	2022	2051	2064	2035	2048
Pickering A – Unit 2/3	Dec, 1971 Jun, 1972	2005	2052/53		2036/2037	
Pickering A – Unit 4	Jun, 1973	2022	2054		2038	
Pickering B – Unit 5	May, 1983	2024	2055	2065	2039	2050
Pickering B – Unit 6	Feb, 1984	2024	2056		2040	
Pickering B – Unit 7	Jan, 1985	2024	2057		2041	
Pickering B – Unit 8	Feb, 1986	2024	2058		2042	
Darlington – Unit 1	Nov, 1992	2053	2084	2093	2068	2077
Darlington – Unit 2	Oct, 1990	2049	2085		2069	
Darlington – Unit 3	Feb, 1993	2052	2086		2070	
Darlington – Unit 4	Jun, 1993	2055	2087		2071	
Bruce A – Unit 1	Sep, 1977	2043	2086	2095	2075	2084
Bruce A – Unit 2	Sep, 1977	2043	2087		2076	
Bruce A – Unit 3	Feb, 1978	2061	2088		2077	
Bruce A – Unit 4	Jan, 1979	2062	2089		2078	
Bruce B – Unit 5	Mar, 1985	2061	2090	2099	2079	2088
Bruce B – Unit 6	Sep, 1984	2057	2091		2080	
Bruce B – Unit 7	Apr, 1986	2063	2092		2081	
Bruce B – Unit 8	May, 1987	2063	2093		2082	

Appendix C: 11 Year Prompt Assumptions

Note: Cash flows were developed from the baseline Safe-Storage scenarios (The four decommissioning cost studies [R 3 to 6]) using the following basic assumptions for the 11 yr deferred case:

General Cost adjustments made to achieve "11 Yr Deferred".

1. The pre-shutdown and transition annual costs from the 30 year scenario were used directly for the annual costs through the end of wet fuel storage (11 years post shutdown). Subsequent Safe-storage years from the 30 year scenario were removed to achieve the shortened storage period.
2. Decon flush costs were added to the transition period costs for each unit. Costs were estimated by taking the costs from the previous estimate and escalating by the blended escalation rate provided by OPG.
3. Pre-dismantling Environmental Assessment costs and Pre-dismantling CNSC Fees are assumed to start at specific times in regard to the start of dismantling. Due to the removal of the "Pre-Dismantling" Safe-storage years to achieve the shortened duration, it was necessary to "overlay" these costs into their specific years. These costs were "overlayed" into the cash flow at the specified times (6 years and 3 years prior to dismantling start respectively). These are "common" costs applied to Unit 0.
4. Due to the shortened timeframe between shutdown and the start of Stage 3, the preparation for dismantling cost for "Review and Revise Plant Dwgs & Specs costs were adjusted down by 50%.
5. Calandria ILW containers and costs were adjusted by artificially increasing the number of ILW containers (25% for 11 yr scenario) in TLG's calandria workbooks for each station. The increase in cost generated by the increase in containers was applied to each of the generating units.
6. The annual costs for the DGR Excavation (2039-2043) and DGR Decommissioning (2100-2105) remain in the currently assumed years.

Pickering Only (11 Year Scenario):

1. Pickering A, Units 2 & 3, due to early shutdown, no adjustments were made.
2. Activated concrete volume was adjusted for a 10% increase in Calandria Activated concrete for Units 1 & 4. This applies to Pickering A only.
3. A CAPEX cost of $200 million was added for the storage of heavy water off-site due to shortened Safe storage period. It is assumed that this OPG provided cost includes a 15% allowance and transportation. This cost is assumed to start 2 years prior to preparation for dismantling start of Pickering A and to be incurred for 2 years. These costs were applied to Pickering B.
4. Interim Heavy Water Storage yearly expenses are assumed to be unchanged as compared to the 30 year.

Bruce A Only (11 Year Scenario):

1. Bruce A, Units 1 & 2, due to earlier shutdown than Units 3 & 4, no adjustments were made.

Report

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Title:

A PRELIMINARY ASSESSMENT TO DETERMINE THE FINANCIAL IMPACT OF USING A PROMPT DECOMMISSIONING APPROACH FOR OPG'S NUCLEAR GENERATING STATIONS

Appendix D: 11 Year Scenario Results

Decommissioning Liability - ONFA 2017 30 Year Deferred vs 11 Year Prompt											Fund Contributions Impact in K$			
Case	Scenario	Pickering A	Pickering B	Bruce A	Bruce B	Darlington	Total	Incr to ONFA Case (All Prompt)	Incr to ONFA Case (PK Only)	Cost	Incr to ONFA Case (All Prompt)	Comments	Incr to ONFA Case (PK Only)	Comments
ONFA 2017	30 Year Deferred	$ 2,692,724	$ 2,626,841	$ 2,572,689	$ 2,673,876	$ 3,534,936	$ 14,101,067			2017k$				
		$ 1,255,877	$ 1,213,645	$ 514,458	$ 507,882	$ 807,641	$ 4,299,502			PV 2017 k$				
Case 0.0	11 Year Prompt	$ 2,479,530	$ 2,683,006	$ 2,446,526	$ 2,600,301	$ 3,366,178	$ 13,575,541			2017k$				
		$ 1,438,172	$ 1,522,543	$ 568,750	$ 565,635	$ 933,280	$ 5,028,379	**$ 728,877**	**$ 491,193**	PV 2017 k$	$ -	No Funding Impact	$ -	No Funding Impact
	Delta from ONFA (Constant$)	-$ 213,194	$ 56,165	-$ 126,164	-$ 73,576	-$ 168,758	-$ 525,526			2017k$				
	Delta from ONFA (pv$)	$ 182,295	$ 308,898	$ 54,292	$ 57,753	$ 125,639	$ 728,877			PV 2017 k$				

Appendix E: 20 Year Deferred Decommissioning Dates

Station/Unit	Unit In-Service Date	2017 ONFA (30 year deferred)			2017 Prompt (20yr deferred)	
		End of Life	Dism.	Site Rest. Complete	Dism.	Site Rest. Complete
Pickering A – Unit 1	Jul, 1971	2022	2051	2064	2044	2056
Pickering A – Unit 2/3	Dec, 1971 Jun, 1972	2005	2052/53		2045/2046	
Pickering A – Unit 4	Jun, 1973	2022	2054		2047	
Pickering B – Unit 5	May, 1983	2024	2055	2065	2046	2056
Pickering B – Unit 6	Feb, 1984	2024	2056		2047	
Pickering B – Unit 7	Jan, 1985	2024	2057		2048	
Pickering B – Unit 8	Feb, 1986	2024	2058		2049	
Darlington – Unit 1	Nov, 1992	2053	2084	2093	2077	2086
Darlington – Unit 2	Oct, 1990	2049	2085		2078	
Darlington – Unit 3	Feb, 1993	2052	2086		2079	
Darlington – Unit 4	Jun, 1993	2055	2087		2080	
Bruce A – Unit 1	Sep, 1977	2043	2086	2095	2084	2093
Bruce A – Unit 2	Sep, 1977	2043	2087		2085	
Bruce A – Unit 3	Feb, 1978	2061	2088		2086	
Bruce A – Unit 4	Jan, 1979	2062	2089		2087	
Bruce B – Unit 5	Mar, 1985	2061	2090	2099	2088	2097
Bruce B – Unit 6	Sep, 1984	2057	2091		2089	
Bruce B – Unit 7	Apr, 1986	2063	2092		2090	
Bruce B – Unit 8	May, 1987	2063	2093		2091	

Appendix F: 20 Year Deferred Assumptions

Note: Cash flows were developed from the baseline Safe-Storage scenarios (The four decommissioning cost studies (R 3 to 6]) using the following basic assumptions for the 20 yr deferred case:

General Cost adjustments made to achieve "20 Yr Deferred".

1. Decon flush costs were added to the transition period costs for each unit. Costs were estimated by taking the costs from the previous estimate and escalating by the blended escalation rate provided by OPG.
2. The shortened Safe-storage duration was achieved by removing the appropriate number of "typical" Safe-storage years from the middle of the 30 year scenario Safe-storage period.
3. Pre-dismantling Environmental Assessment costs and Pre-dismantling CNSC Fees are included in the annual "pre-dismantling" Safe-storage costs linked into the cash flow. Therefore, these costs do not need to be "overlayed" into the 20 year scenarios. These are "common" costs applied to Unit 0.
4. Calandria ILW containers and costs were adjusted by artificially increasing the number of ILW containers (10% for 20 yr scenario) in TLG's Calandria workbooks for each station. The increase in cost generated by the increase in containers was applied to each of the generating units.
5. The annual costs for the DGR Excavation (2039-2043) and DGR Decommissioning (2100-2105) remain in the currently assumed years.

Pickering Only (20 Year Scenario):

1. Pickering A, Units 2 & 3, due to early shutdown no adjustments were made.
2. Activated concrete volume was adjusted for a 5% increase in Calandria Activated concrete for Units 1 & 4. Pickering A only.
3. A CAPEX cost of $200 million was added for the storage of heavy water off-site due to shortened storage period. It is assumed that this OPG provided cost includes a 15% allowance and transportation. This cost is assumed to start 2 years prior to preparation for dismantling start of Pickering A and to be incurred for 2 years. These costs were applied to Pickering B.
4. Interim Heavy Water Storage yearly expenses are assumed to be unchanged as compared to the 30 year scenario.

Bruce A Only (20 Year Scenario):

1. Bruce A, Units 1 & 2, due to earlier shutdown than Units 3 & 4, no adjustments were made.

Appendix G: 20 Year Scenario Results

Decommissioning Liability - ONFA 2017 30 Year Deferred vs 20 Year Prompt											Fund Contributions Impact in K$			
Case	Scenario	Pickering A	Pickering B	Bruce A	Bruce B	Darlington	Total	Incr to ONFA Case (All Prompt)	Incr to ONFA Case (PK Only)	Cost	Incr to ONFA Case (All Prompt)	Comments	Incr to ONFA Case (PK Only)	Comments
ONFA 2017	30 Year Deferred	$ 2,692,724	$ 2,626,841	$ 2,572,689	$ 2,673,876	$ 3,534,936	$ 14,101,067			2017k$				
		$ 1,255,877	$ 1,213,645	$ 514,458	$ 507,882	$ 807,641	$ 4,299,502			PV 2017 k$				
Case 0.0	20 Year Prompt	$ 2,495,405	$ 2,690,427	$ 2,570,918	$ 2,687,295	$ 3,477,976	$ 13,922,023			2017k$				
		$ 1,289,030	$ 1,387,863	$ 527,062	$ 521,485	$ 821,567	$ 4,547,007	**$ 247,505**	**$ 207,371**	PV 2017 k$	$ -	No Funding Impact	$ -	No Funding Impact
	Delta from ONFA (Constant$)	-$ 197,319	$ 63,587	-$ 1,771	$ 13,419	-$ 56,959	-$ 179,044			2017k$				
	Delta from ONFA (pv$)	$ 33,153	$ 174,218	$ 12,605	$ 13,603	$ 13,926	$ 247,505			PV 2017 k$				

Appendix H: OPG Deferred Decommissioning Stage Detail

The following sub-sections describe the activities associated with the current OPG deferred decommissioning approach. The stage descriptions have been extracted from the Darlington GS Decommissioning Cost Study but are common to all OPG nuclear generating stations. [R-3]

STAGE 1 – Preparation for Safe Storage

In anticipation of the cessation of station operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. The organization required to manage the intended decommissioning program is assembled from available plant staff and outside resources, as required. Preparations include the planning for permanent defueling of the reactors, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the safe storage plan.

At least four or five years prior to the scheduled shutdown, OPG would start conceptual engineering and planning of the decommissioning. Preliminary site radiological characterization would also be initiated at this time, with subsequent (more detailed) characterization performed as needed. OPG will submit a detailed decommissioning plan towards the end of the safe storage period consistent with the timing of an application for a decommissioning license to the CNSC. This submittal would include a description of the planned safe storage activities, a corresponding schedule, and an estimate of expected costs. It would also address any un-reviewed environmental impacts associated with the proposed decommissioning scenario. Existing operational technical specifications will require review and modification to reflect plant conditions and the safety concerns consistent with permanent cessation of operations.
The process of placing a unit in safe storage includes, but is not limited to, the following activities, which are expected to occur after unit shutdown:

- Defuel the reactor, transferring the used fuel to the intermediate storage pool. This activity will be carried out by plant personnel in accordance with existing operating technical specifications. The existing used fuel storage facilities will continue to operate until the used fuel is either transferred to the fuel repository or to dry storage.
- Drain the heavy water from the moderator and primary heat transport systems.
- Drain/de-energize/secure all non-contaminated systems not required to support dormancy operations.
- Dispose of contaminated filter elements and resin beds not required for processing wastes from decontamination activities.
- Drain/de-energize/secure all contaminated systems. Decontaminate systems as required for future maintenance and inspection.
- Prepare lighting and alarm systems whose continued use is required. Consistent with any code requirements de-energize and/or secure portions of fire protection, electric

power, and heating, ventilation and air-conditioning (HVAC) systems whose continued use is not required.
- Clean loose surface contamination from building access pathways.
- Perform a site characterization of the plant and the licensed site.
- Perform an interim radiation survey of plant; post warning signs as appropriate.
- Erect physical barriers and/or secure all access to radioactive or contaminated areas, except as required for controlled access, i.e., inspection and maintenance.
- Install security and surveillance monitoring equipment and relocate security fence around secured structures, as required.

The cost estimates assume that demolition would be delayed for those structures located outside the secured area (licensed area) until after all radioactive material in excess of release levels has been removed.

STAGE 2 – Safe Storage

Activities required during the planned dormancy period for the Safe Storage strategy include 24-hour security, preventive and corrective maintenance on security systems, area lighting, general building maintenance, fire protection, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. The duration of the dormancy period was selected such that the dismantling operations are initiated after a nominal period of 30 years.

Equipment maintenance, inspection activities, and routine service are performed by resident maintenance personnel. This work force will maintain the structures in a safe condition, provide adequate lighting, heating, and ventilation, and perform periodic preventive maintenance on essential site equipment.

An environmental surveillance program is carried out during the dormancy period to ensure that potential adverse releases of radioactive material to the environment are controlled and prevented. Appropriate emergency procedures are established and initiated for releases that could exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations. A small plant staff is maintained during this period to support the maintenance, inspection, and surveillance programs.

Security during the dormancy period is conducted primarily to prevent unauthorized entry and to protect the public from the consequences of its own actions. Security will be provided by the security fence, sensors, alarms, surveillance equipment, etc., that must be maintained in good condition for the duration of this period. Fire and radiation alarms are also to be monitored and maintained.

STAGE 3A – Preparations for Dismantling

After a nominal 30 year safe storage period and in anticipation of dismantling, detailed preparations are undertaken to provide a smooth transition from safe storage to site dismantling. The organization required to manage the intended dismantling activities is assembled from available plant staff at Darlington and other OPG stations, and from outside resources as required. Preparations include a detailed physical and radiological characterization of the facility and major components, and the development of the dismantling or license termination plan.

Planning would include a site characterization, description of the dismantling activities, plans for site remediation, detailed plans for the final radiation survey, designation of the end-use of the site, an updated cost estimate to complete the dismantling, and any associated plans for environmental remediation.

Although the initial radiation levels due to 60Co will decrease significantly during the safe storage period, the internal components of the calandria will still exhibit sufficiently high radiation dose rates to require remote sectioning due to the presence of long-lived radionuclides. Portions of the biological shield will still be radioactive due to the presence of activated trace elements with long half-lives (152Eu and 154Eu).

Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components are surveyed as they are removed and disposed of in accordance with the prevailing radiological release criteria.

Prior to the commencement of dismantling operations, preparations are undertaken to reactivate site services and prepare for dismantling. Activity specifications and detailed procedures are also developed at this time.

Engineering and Planning

The dismantling operations will be designed to accomplish the required tasks within the ALARA guidelines for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity.

Much of the work in preparing the plan is also relevant to the development of the detailed engineering plans and procedures. This work includes, but is not limited to:

- Site preparation plans for the proposed dismantling activities.
- Detailed procedures and sequences for removal of systems and components.
- Evaluation of the disposition and selection of the most suitable option for the calandria and its internals.

- Plans for decontamination of structures and systems.
- Design/procurement and testing of tooling and equipment.
- Identification/selection of specialty contractors.
- Procedures for removal and disposal of radioactive materials.
- Sequential planning of activities to minimize conflicts with simultaneous tasks.

Site Preparations

In preparation for dismantling, the following activities are initiated.

- Prepare site support and storage facilities, as required.
- Perform site characterization study to determine extent of site contamination.
- Clean all plant areas of loose contamination and process all liquid and solid wastes.
- Conduct radiation surveys of work areas, major components (including the calandria and internals), sampling of internal piping contamination levels, and primary shield cores.
- Correlate survey data and normalize for development of packaging and transportation procedures.
- Determine transport and disposal container requirements for activated materials and/or hazardous materials, including shielding and stabilization. Fabricate or procure such containers.
- Develop procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste including; resins, filter media, metallic and non-metallic components generated in dismantling, site security and emergency programs, and industrial safety.

STAGE 3B - Dismantling

Significant dismantling activities involve the following steps:

- Construct temporary facilities and modify existing storage facilities to support the dismantling activities. These may include a cutting station (for boilers and other large components), additional changing rooms and contaminated laundry facilities for increased work force, establishment of laydown areas to facilitate equipment removal, upgrading roads to facilitate hauling and transportation, and modifications to the reactor building to facilitate access of large/heavy equipment.
- Design and fabricate shielding and contamination control envelopes to support removal and transportation activities. Specify and/or procure specialty tooling and remotely operated equipment. Modify containment to support segmentation activities and prepare rigging for segmentation and extraction of heavy components, including the steam generators.
- Procure required shipping canisters, cask liners, and Industrial Packages (IPs) from suppliers.

- Conduct decontamination of components and piping systems as required to control (minimize) worker exposure. Remove, package, and dispose of all piping and components that are no longer essential to support dismantling operations.
- Remove steam generators for shipment and controlled disposal. The steam generators will be segmented prior to disposal. They are considered large objects which exceed the waste disposal facility size/weight guidelines. After segmentation, decontaminate exterior surfaces, as required, and seal-weld openings (nozzles, inspection hatches, and other penetrations). The segmented sections can serve as their own disposal containers provided that all penetrations are properly sealed and the internal contaminants are stabilized.
- At each calandria face, remove the fuelling machine bridge structure and insulated feeder cabinet which encloses the PHT headers and feeder tubes.
- Remove the PHT and moderator piping and pumps. Package the piping in IPs; the pumps are sealed with steel plate so as to serve as their own containers. Segment those components that are considered large object waste that exceed the waste disposal facility size guidelines. Ship piping and pumps for disposal.
- Install calandria segmentation system in reactor vault and test.
- Modify existing used fuel handling system in fuelling duct and Unit 0 to handle segmented portions of the calandria.
- Segment the calandria/shield tank structure, removing the ILW first. Major activities will include the following:
    - Install temporary shielding as necessary.
    - Remove all horizontal and vertical control elements and their associated drive mechanisms.
    - Cut welds and remove end fittings and pressure tubes from calandria; cut into lengths to fit shielded cask liners for disposal.
    - Cut welds and remove calandria tubes from calandria structure; cut into lengths to fit shielded cask liners for disposal.
    - In parallel with the pressure tube and calandria tube removal, begin removal of the steel shot in the calandria faces. Shot removal must be coordinated with pressure tube and calandria tube removal to minimize area doses to segmentation crew.
    - Transport all waste to Unit 0 for packaging via modified used fuel handling system.
    - Segment the balance of the calandria structure.
- Remove the balance of the systems and equipment from the reactor vault, including the pressurizer and bleed cooler. These components will be segmented prior to disposal. They are considered large object waste that exceeds the waste disposal facility size guidelines. Decontaminate exterior surfaces, as required, and seal-weld openings (nozzles, inspection hatches, and other penetrations). The segmented sections can serve as their own disposal containers provided that all penetrations are properly sealed and the internal contaminants are stabilized.
- Remove systems and associated components as they become non-essential to the vessel removal operation, related decommissioning activities, or worker health and

safety (e.g., waste collection and processing systems, electrical and ventilation systems, etc.).

- Remove activated concrete biological shield and accessible contaminated concrete. Remove those portions of the associated enclosures necessary for access and component extraction.
- Remove contaminated equipment and material from the Central Service Area, Fuelling Facilities Auxiliary Areas, D2O and TRF facilities, and Vacuum Structure. Remediate until radiation surveys indicate that the structure can be released for unrestricted access.
- Remove all remaining LLW and ILW along with any remaining hazardous and toxic materials. Material removed in the decontamination and dismantling of the nuclear units will be routed to an on-site central processing area. Material that meets clearance criteria will be released for unrestricted disposition, e.g., as scrap, recycle or general disposal. Contaminated material will be characterized and packaged for controlled disposal at a licensed regional facility located in Ontario.
- Remove remaining components, equipment, and plant services in support of the area release survey(s).
- Conduct final radiation survey to ensure that all radioactive materials in excess of permissible residual levels have been remediated. This survey may coincide with the regulator's site inspection. A termination survey can be developed using a guidance document such as the "Multi-Agency Radiation and Site Investigation Manual," issued by the U.S. NRC. This manual delineates the statistical approaches to survey design and data interpretation. It also identifies state-of-the-art, commercially available, instrumentation and procedures for conducting radiological surveys. Use of guidance such as this ensures that survey design and implementation are conducted in a manner that provides a high degree of confidence that applicable criteria are satisfied. Once the survey is complete, the results are provided to the regulator(s) in a format that can be verified. The regulator can then review and evaluate the information, perform an independent confirmation of radiological site conditions, and make a determination on final abandonment of the decommissioning license.

STAGE 3C – Site Restoration

Site restoration activities may begin following the completion of dismantling operations. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below regulatory limits will result in substantial damage to many of the structures. Blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially damage power block structures including the reactor vault, reactor auxiliary bay, fuelling facilities auxiliary areas and central service area. Verifying that subsurface radionuclide concentrations meet site release requirements may require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal activity will be necessary for those facilities and plant areas where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been

recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

It is assumed that non-essential structures and site facilities will be dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are assumed to be removed to a nominal depth of one meter below grade whenever possible. Foundation grade slabs greater than one meter in thickness are abandoned in place and covered over with a one meter layer of fill. The one meter depth allows for the placement of both gravel for drainage and topsoil for erosion control through vegetation. Site areas affected by the dismantling activities are cleaned and the plant area graded as required to prevent ponding and inhibit the resurfacing of subsurface materials. Activities include:

- Perform demolition of the remaining portions of the reactor auxiliary bays, reactor vaults, fuelling facilities auxiliary areas, and central service area. Internal floors and walls are removed from the lower levels upward, using controlled blasting techniques. Concrete rubble and clean fill produced by demolition activities are used on-site to backfill voids. Suitable materials can be used on site for fill; otherwise the rubble is trucked off site for disposal as construction debris.
- Remove remaining buildings using conventional demolition techniques for above ground structures, including the turbine halls, vacuum building, and other site structures.
- Prepare the final decommissioning program report.
- Apply for a License to Abandon from the CNSC.

UNDERTAKING J13.8

Undertaking

Reference: K13.2, page 22

To provide nuclear rates on yearly basis as provided to the IESO. Explain how rates were calculated and how incremental and non-incremental costs were factored in on best efforts basis.

Response

The "unsmoothed" nuclear rates that OPG provided to the IESO in 2015 are shown in Chart 1 below (constant 2015$).

Chart 1

$/MWh	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Base Case (Pickering to 2020)	69	86	83	82	82	182	169	213	128
Pickering Extended Operations (62 TWh scenario)	69	89	81	84	93	98	100	112	88

The nuclear rates shown in Chart 1 were calculated in a manner consistent with how proposed nuclear payment amounts are calculated and reflect total costs and production associated with both Pickering and Darlington based on the information provided to the IESO in 2015. The total costs include incremental costs associated with Pickering Extended Operations as well as all other non-incremental costs that factor into OPG's nuclear payment amounts. The classification of incremental and non-incremental costs associated with Pickering Extended Operations is not a relevant consideration for establishing the nuclear rates shown in Chart 1.

The IESO described how the rates in Chart 1 were factored into their analysis at Tr. Vol. 12, p. 16.

UNDERTAKING J13.9

Undertaking

Reference: Table in K13.2, p. 23.

To provide on a best-efforts basis the underlying staffing assumptions in the incremental cost figures that are used in the net benefit analysis.

Response

Chart 1 provides an approximation OPG-employed regular and non-regular full time equivalent ("FTE") numbers related to the Pickering extension in a format consistent with Ex. K13.2, p. 23.

OPG's costs include both labour and non-labour components (e.g. materials, purchased services, etc). OPG did not directly consider labour cost FTEs in determining all aspects of incremental and non-incremental costs for the Pickering Extension net benefit analysis, as discussed at Tr. Vol. 13, p. 145. For the purpose of this response, FTE information has been approximated on a best efforts basis, taking into account direct station labour costs and an estimated labour portion of support costs based on the relative proportion of labour in OPG's total support costs.

Chart 1: Pickering Generating Station Approximated FTEs in 2021 to 2024 Period

	2021	**2022**	**2023**	**2024**
Approximate FTEs corresponding to estimated labour component of fully allocated costs	4,400	4,000	2,900	2,800
Approximate FTEs corresponding to estimated labour component of incremental costs	3,600	3,400	2,600	2,500
Approximate FTEs corresponding to estimated labour component of non-incremental costs	800	600	300	300

UNDERTAKING J13.10

Undertaking

TO CONFIRM WHETHER OPG HAS INCLUDED COSTS OF EXPANDING NUCLEAR WASTE FUEL STORAGE FACILITIES AT PICKERING AS PART OF INCREMENTAL COSTS FOR THE PURPOSES OF ITS COST-BENEFIT ANALYSIS.

Response

Confirmed. OPG's economic assessment of Pickering Extended Operations at Ex. F2-2-3 Attachment 2 reflects approximately $134M of incremental costs associated with used fuel storage and disposal under the 62 TWh scenario.

UNDERTAKING J13.11

Undertaking

To provide the average cost of capacity per unit assumed in OPG Net Benefit Analysis. To provide an actual cost of capacity included in analysis (the number equivalent to the IESO's $800M), on a best efforts basis (i.e. rate and total).

Response

The average cost of replacement capacity per unit assumed in OPG's economic assessment of Pickering Extended Operations was $113.5/kW-year. This is based on the assumption that incremental capacity is provided by single-cycle gas turbines.

The total cost of replacement capacity reflected in OPG's economic assessment is approximately $775M ($2015 net present value).

UNDERTAKING J13.12

Undertaking

To provide assumptions in OPG net benefit analysis relating to availability on peak for Pickering and gas facilities (i.e., did OPG assume same availability between gas and Pickering or otherwise).

Response

Please see response to Undertaking J13.13.

UNDERTAKING J13.13

Undertaking

To provide a side-by-side comparison between OPG's availability on peak assumptions against the IESO's assumptions on these values, on a best efforts basis.

Response

OPG's and IESO's assumptions for availability at summer peak are shown in Chart 1.

Chart 1

	OPG	IESO
Pickering	100%	99%
Single Cycle Gas Turbine	100%	n/a
Combined Cycle Gas Turbine	72% - 89%	n/a
Natural gas	n/a	89%
Source	J15.1	JT 1.17H, #7

UNDERTAKING J13.14

Undertaking

To provide OPG's calculated equivalent Forced Outage Rate on demand for gas and nuclear, and if not, to please advise the Panel on how long it would take to calculate on best efforts basis.

Response

As described at Tr. Vol. 14, pp. 77-78, OPG does not calculate the equivalent forced outage rate on demand and doing so would require a new modeling effort and additional data.

UNDERTAKING J14.1

Undertaking

To provide Nuclear In-Service 2016 year end numbers, on same basis as Ex. D2-1-3, Table 4.

Response

An update of Ex. D2-1-3 Table 4 to include nuclear in-service 2016 year end numbers is provided in Attachment 1.

The lower 2016 actual nuclear in-service capital amounts compared to the 2016 budget reflects project delays and deferrals that moved some or all of the planned in-service declarations for each applicable project beyond 2016.

As of Q1 2017, $70.3M that was planned for 2016 has been placed in-service in 2017. This shift from 2016 into 2017 is in addition to the forecast in-service amount for 2017.

Numbers may not add due to rounding.

Table 1
D2-1-3 Table 4 Updated for 2016 Actuals
Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	89.9	(10.0)	79.9	(48.8)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	**Pickering NGS**	53.6	41.3	94.9	(26.2)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	**Nuclear Support Divisions**[1]	17.4	10.2	27.6	(1.6)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	**Subtotal**	160.8	41.6	202.4	(76.7)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	**Supplemental In-Service Forecast**[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	**Total Portfolio In-Service Forecast**	160.8	41.6	202.4	(76.7)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	**Minor Fixed Assets**	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	**Total In-Service Capital Additions**	180.7	31.9	212.6	(64.0)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(e)-(a) Change	2016 Budget	(e)-(c) Change	2016 Actual	(g)-(e) Change	2017 Plan	(i)-(g) Change	2018 Plan	(k)-(i) Change	2019 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Darlington NGS**	107.0	112.8	331.4	(111.6)	219.8	(38.4)	181.3	(29.4)	152.0	10.4	162.4
10	**Pickering NGS**	71.7	(23.8)	164.9	(117.0)	47.9	38.1	86.0	(70.2)	15.8	(13.0)	2.8
11	**Nuclear Support Divisions**[1]	3.1	(1.3)	17.1	(15.3)	1.8	5.1	6.9	(3.3)	3.6	(3.6)	0.0
12	**Subtotal**	181.8	87.7	513.4	(243.9)	269.5	4.8	274.3	(102.9)	171.4	(6.2)	165.2
13	**Supplemental In-Service Forecast**[2]	0.0	0.0	(47.4)	47.4	0.0	88.7	88.7	35.1	123.8	(68.8)	55.0
14	**Total Portfolio In-Service Forecast**	181.8	87.7	466.0	(196.5)	269.5	93.5	363.0	(67.7)	295.2	(75.0)	220.2
15	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Minor Fixed Assets**	22.3	0.2	31.0	(8.5)	22.5	3.5	26.0	(6.0)	20.0	(0.9)	19.1
17	**Total In-Service Capital Additions**	204.1	87.9	497.0	(205.0)	292.0	97.0	389.0	(73.7)	315.2	(75.9)	239.3

Line No.	Business Unit	2019 Plan	(c)-(a) Change	2020 Plan	(e)-(c) Change	2021 Plan
		(a)	(b)	(c)	(d)	(e)
18	**Darlington NGS**	162.4	(102.4)	60.0	(21.3)	38.7
19	**Pickering NGS**	2.8	(2.8)	0.0	0.0	0.0
20	**Nuclear Support Divisions**[1]	0.0	0.0	0.0	0.0	0.0
21	**Subtotal**	165.2	(105.3)	60.0	(21.3)	38.7
22	**Supplemental In-Service Forecast**[2]	55.0	150.7	205.7	(48.0)	157.6
23	**Total Portfolio In-Service Forecast**	220.2	45.4	265.6	(69.3)	196.3
24	**Darlington New Fuel**	0.0	15.3	15.3	(15.3)	0.0
25	**Minor Fixed Assets**	19.1	0.4	19.5	(0.1)	19.3
26	**Total In-Service Capital Additions**	239.3	61.1	300.4	(84.8)	215.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

UNDERTAKING J14.2

Undertaking

To update Ex. F2-1-1, Table 1 for 2016 actual.

Response

An update of Ex F2-1-1, Table 1 for 2016 actual costs is provided in Attachment 1.

F2-1-1 Table 1 Updated for 2016 Actuals
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,182.4	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	89.3	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	306.7	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,578.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	3.1	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	0.6	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	426.2	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	329.3	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	34.1	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	793.2	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,371.5	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	263.1	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	278.1	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(36.5)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	14.1	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,890.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Notes:

1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.2M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.

2 Comprises centrally-held costs and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

UNDERTAKING J14.3

Undertaking

To update Ex. F2-2-1, Table 2 for 2016 actual.

Response

An update of Ex. F2-2-1, Table 2 to include 2016 Base OM&A Actuals is provided in Attachment 1.

The increase in Base OM&A from 2015 to 2016 is primarily due to an inventory write-off (reflected in the Other Base OM&A category) as well as overtime and purchased services requirements. Base labour declined due to greater than anticipated attrition, which OPG was able to partially offset by a revised mix of additional overtime and other purchase services.

While the mix of Base OM&A fluctuates each year, total Base OM&A is forecast to grow at a steady rate over the Test Period, in line with historical actuals.

Numbers may not add due to rounding.

F2-2-1 Table 2 Updated for 2016 Actuals
Base OM&A - Nuclear ($M)

Line No.	Resource Type	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Labour**[1]	832.4	827.1	834.0	807.2	859.0	846.9	874.3	885.0	887.9
2	**Overtime**[1]	48.6	46.7	54.5	63.7	46.1	46.5	46.1	47.4	47.8
3	**Augmented Staff**	3.1	3.6	4.4	6.7	4.5	3.5	3.0	2.6	1.6
4	**Materials**	85.1	73.4	83.4	81.7	68.4	68.2	68.5	71.1	70.8
5	**License**	34.2	32.6	34.5	36.0	37.2	38.7	39.6	40.2	40.6
6	**Other Purchased Services**	100.0	98.7	108.4	129.1	161.1	185.1	180.8	178.3	187.3
7	**Other**	24.3	44.9	40.3	58.0	34.2	37.0	36.2	40.2	40.3
8	**Total Base OM&A**	1,127.7	1,127.1	1,159.6	1,182.4	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3

Notes:
1 Includes Regular and Non-Regular staff.

UNDERTAKING J14.4

Undertaking

To provide 2013-2015 actual values for EB-2013-0321, Ex. F2-1-1, p. 14, Chart 3, specifically with respect to WANO, FLR, Unit Capability and All Value for Money.

And to provide 2016 actual results for WANO, FLR, Unit Capability and All Value for Money

Response

Table 1 below provides 2013-2016 actual values for WANO NPI, FLR, Unit Capability Factor and Value for Money.

Table 1

NPI (Index)	2013	2014	2015	2016
Pickering	67.5	64.4	68.5	76.3
Darlington	90.8	92.1	83.7	87.7

FLR (%)	2013	2014	2015	2016
Pickering	9.78	10.88	2.83	4.92
Darlington	5.25	1.53	5.10	3.17

UCF (%)	2013	2014	2015	2016
Pickering	73.71	75.28	79.35	74.71
Darlington	82.92	92.09	76.86	83.98

Total Generating Cost per MWH ($)	2013	2014	2015	2016
Pickering	69.62	68.78	63.91	71.82
Darlington	42.31	39.63	52.31	46.11

Non-Fuel Operating Cost per MWH	2013	2014	2015	2016
Pickering	58.54	57.18	53.95	60.45
Darlington	33.61	28.33	38.59	33.01

Fuel Cost per MWH ($)	2013	2014	2015	2016
Pickering	5.81	5.65	5.68	5.93
Darlington	5.21	5.05	5.31	5.60

Capital Costper MW DER ($)	2013	2014	2015	2016
Pickering	33.53	38.62	29.42	35.10
Darlington	24.88	49.86	55.82	54.72

UNDERTAKING J14.5

Undertaking

TO PROVIDE RESULTS FOR 2012-2016 FOR BOTH METRICS IN STAFF 106, COLOUR-CODING THE RESULTS TO SHOW THE QUARTILE FOR EACH METRIC FALLS INTO DURING THAT PERIOD.

Response

Chart 1 and Chart 2 below update results for scope stability and schedule adherence metrics for the years 2015 and 2016.

As noted in Scott Madden's Evaluation of OPG Nuclear Benchmarking report (Ex. F2-1-1, Attachment 3, p. 12), these metrics are relatively new for the industry and data is not yet consistently reported.

Ontario Power Generation as an International member of the Institute of Nuclear Power Operators ("INPO") participates in the work management working group meetings each year. The top quartile benchmark data provided below was obtained through OPG's participation in these working meetings. However detailed benchmark data for quartile comparison is not currently available and therefore colour coding by quartiles is not possible.

A benchmark survey of Candu operators in Canada was also completed by OPG for Scope Stability and Schedule Adherence (completion) in the fourth quarter of 2016. The Candu averages are noted below for reference.

Top quartile (INPO working group) for scope stability is benchmarked at 92%. OPG targets performance of 80 per cent for Darlington and 75 per cent for Pickering. These targets are based on:

- Past performance: Darlington has averaged 73% and Pickering has averaged 63% since 2012. There are initiatives currently underway to improve performance on this metric.
- Technology: Scope stability tracks the amount of work that stays on schedule for eight weeks out prior to execution of the task (Tr. Vol. 14, p.110). Scope stability is critical to successful completion of a work management program because scope additions or changes will lead to schedule delays and failure to complete schedule tasks. The INPO working group is primarily made up of PWR/BWR reactors. The number of tasks under work management programs for PWR/BWR reactors are typically less than CANDU reactors because of different technology. For example CANDU technology requires online fuelling to be incorporated into work management program, adding to complexity and potential for the need for changes in scope.

- Single-unit versus multi-unit stations: In a multi-unit station each unit is dependent on the other to facilitate the execution of the work on the schedule. In particular, for electrical and channelized maintenance if components become unavailable during the eight week period it will impact the availability of work that can be scheduled and cause work to be removed from scope. For multi unit stations this factor affects the stability of the working schedule. By comparison, the INPO top quartile reflects a number of single unit stations where the number of incoming work orders are minimal.

Chart 1 - Scope Stability

	2012				2013				2014			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
DN	83%	84%	80%	69%	84%	75%	72%	67%	61%	71%	61%	68%
PN	62%	55%	60%	54%	51%	53%	68%	56%	64%	63%	65%	62%
Candu Avg.	67%				67%				64%			

	2015				2016			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
DN	70%	78%	69%	72%	64%	82%	74%	76%
PN	67%	70%	66%	70%	69%	63%	70%	70%
Candu Avg.	75%				73%			

For Schedule Adherence, OPG uses Schedule Completion to benchmark performance. Top quartile (INPO working group) is benchmarked at 95%. OPG targets performance of 95% for Darlington and 91% for Pickering. Pickering's target reflects the impact of emergent corrective work that in some cases diverts resources from planned work. Darlington's target of 95% is top quartile performance.

Chart 2 - Schedule Adherence

	2012				2013				2014			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
DN	89%	90%	88%	88%	93%	88%	88%	88%	84%	86%	87%	88%
PN	89%	88%	87%	88%	85%	88%	88%	85%	86%	86%	86%	86%
Candu Avg	89%				88%				88%			

	2015				2016			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
DN	87%	88%	86%	86%	87%	90%	88%	88%
PN	88%	87%	87%	87%	91%	89%	88%	88%
Candu Avg	84%				87%			

UNDERTAKING J14.6

Undertaking

TO PROVIDE THE 2016 ACTUAL NUCLEAR ALLOCATED FTES.

Response

Table 1 below provides the Nuclear Direct FTEs provided in the response to Undertaking J13.3, plus Nuclear Allocated FTEs.

Table 1

Line No.	Group	2013 Actual[2]	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NUCLEAR OPERATIONS:									
1	**Regular Staff**	5,870.7	5,626.7	5,430.4	5,341.1	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
2	**Non-Regular Staff**	496.9	578.1	670.0	843.8	614.4	646.6	632.2	526.8	420.4
3	**Subtotal Nuclear Operations**	6,367.6	6,204.8	6,100.4	6,184.9	6,325.2	6,312.8	6,234.3	6,030.9	5,815.1
	DARLINGTON REFURBISHMENT:									
4	**Regular Staff**	282.0	307.2	329.7	422.6	587.2	599.9	620.5	589.5	597.8
5	**Non-Regular Staff**	24.6	35.3	60.7	112.7	153.2	152.2	137.4	157.7	230.1
6	**Subtotal Nuclear Generation Development**	306.6	342.5	390.4	535.3	740.4	752.1	757.9	747.2	827.9
7	**Total Nuclear Direct**	6,674.2	6,547.3	6,490.8	6,720.2	7,065.6	7,064.9	6,992.2	6,778.1	6,643.0
8	**NUCLEAR ALLOCATED[3]**	1,919.5	1,884.4	1,628.9	1,659.8	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
9	**Total Nuclear [4]**	8,593.7	8,431.7	8,119.7	8,380.0	8,808.4	8,768.6	8,672.0	8,437.1	8,299.2

1 Nuclear Operations and Darlington Refurbishment FTEs are aligned to where costs related to the FTEs are incurred.
2 The 2013 Actual FTEs shown are adjusted from those provided in EB-2013-0321, Ex. J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.
3 Ex. F4-3-1, Attachment 1 updated for 2016 actual FTEs
4 Does not include adjustment discussed in L-6.6-1 Staff-139(a)

UNDERTAKING J15.1

Undertaking

With reference to Hearing Transcript Volume 14, p. 78, to provide the assumptions related to and the basis upon which the forced outage rates were used in OPG's model for the Pickering Extended Operations Business Case.

Response

To account for the frequency of unplanned outages throughout the year in its economic assessment of Pickering Extended Operations, OPG assumed an equivalent forced outage rate ("EFOR") of 8.3% - 8.4% for Pickering A units and 5.3% - 5.9% for Pickering B units, depending on the year. OPG assumed a constant EFOR of 5% for both single cycle gas turbines ("SCGT") and combined cycle gas turbines ("CCGT").

On a capacity basis, OPG's economic assessment assumed a resource availability at summer peak of 100% for both Pickering and SCGTs and between 72% - 89% for CCGTs. In addition, a reserve margin of 17% is assumed to enable supply resource adequacy in the event of a forced outage occurrence at summer peak.

As noted in J13.14, OPG does not calculate equivalent forced outage rate on demand.

UNDERTAKING J15.2

Undertaking

Reference: L-4.4-15 SEC-048

To provide:

(1) OPG-STD-0017 (Organizational Authority Register) and OPG-STD-0076 (Developing and Documenting Business Cases), or otherwise identify where they have been filed in the Application; and

(2) The versions of OPG-STD-0017 and OPG-STD-0076 that were in place in EB-2013-0321.

Response

Attachments 1 and 2 respectively are the most current version of OPG-STD-0017 (Organizational Authority Register) and OPG-STD-0076 (Developing and Documenting Business Cases).

Attachments 3 and 4 respectively are the versions of OPG-STD-0017 and OPG-STD-0076 that were in place in EB-2013-0321.

ONTARIO POWER GENERATION

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Standard

TITLE
ORGANIZATIONAL AUTHORITY REGISTER

AUTHORIZATION	
SINGLE POINT OF CONTACT:	D. Fairbarn Senior Manager, Shared Financial Services Systems
DOCUMENT OWNER:	G. Inouye Vice-President, Shared Financial Services

DOCUMENT RELATIONSHIP	
Applicability:	OPG Wide
Receives Authority from:	OPG-POL-0024, Delegation and Exercise of Authority

PURPOSE

The Ontario Power Generation Organizational Authority Register (OAR) provides a framework of delegated authorities and position holders to whom the authority is delegated. Authority is the right to transact on behalf of, bind OPG, or exercising certain decision rights on behalf of OPG. This standard is restricted to a listing of:

(a) allowable dollar limits for final approval of financial transactions for given position holders; and

(b) guiding principles for exercise of the authority delegated herein.

References to process governing documents are included, where applicable.

DATES (YYYY-MM-DD)	
PDF Creation Date:	2016-09-28
Compliance Date:	Immediate

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EXCEPTIONS

The positions described in the OAR are in relation to OPG and not in relation to subsidiaries or joint ventures. Accordingly, an approval required under the OPG OAR must be received from the OPG position holder unless specific approval authority is granted by the OPG Board and Chief Executive Officer (CEO). Where a subsidiary has its own OAR, authorities shall be consistent with this standard. Refer to the Wholly-Owned Subsidiary Governance (OPG-STD-0094) and Joint Venture Governance (OPG-STD-0093) for the applicability of OPG OAR to subsidiaries and joint ventures.

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1.0 DIRECTION

1.1 Guiding Principles for the Exercise of Authority

1.1.1 Transactions not specifically listed in the OAR have not been delegated by OPG's Board.

1.1.2 Approval is based on the total financial commitment (in Canadian dollars), and shall be tied to a proper bundling of work.

1.1.3 Authorities exercised shall be consistent with approved business plan and budget, unless specified otherwise.

1.1.4 The original initiator of a transaction cannot be the approver even if the transaction is within their assigned authority limits. This principle does not apply to energy trading transactions which have compensating controls.

1.1.5 If a specific transaction is covered by a specific Element, the transaction cannot be approved under another Element.

1.1.6 Authorities may be delegated on a temporary basis for a maximum of 3 months in situations where the position holder is unavailable to exercise his/her authority, provided there is no conflict of interest. Authority delegations are effective on the date approved unless otherwise specified. The delegator shall keep a record of delegation for a period of time consistent with OPG-PROC-0019 Records and Document Management.

1.1.7 An incumbent occupying two positions may exercise the authority of both of those positions except where doing so would violate an established internal control or result in a conflict of interest.

1.1.8 Finance's approval supports the Chief Financial Officers (CFO) role in reviewing material financial transactions and the financial implications of general business activities. Where Finance Approval is required, approval shall be obtained from the Station/Plant Group/Nuclear, Band G Corporate Functions Controller or Senior Manager Accounting, as applicable or as otherwise specified in referenced governance. Where Finance's review is part of the general transaction or activity workflow, additional approval by Finance may not be necessary.

1.1.9 The authority to requisition and purchase equipment, material, fuel, and contracted service in an emergency (as defined in the OPG Emergency Preparedness and Response Plan, OPG-STD-0091) is temporarily delegated to station management at Band F and up for purposes of responding to the emergency. Management discretion is to be applied in the exercise of this temporary authority delegation. Both requisitioning and purchasing approvals shall be obtained from appropriate position holders at the earliest convenience during or immediately after the emergency.

1.2 Determination of Authority Level

Authority is determined by the position, and the decision rules are to be applied in the order given below.

Rule One: Authorities for CEO, Enterprise Leadership Team (ELT) Members and Senior Vice President (SVP) are specifically listed by title/ELT membership

Rule Two: Authority for Management employees is determined by Management Group Band D to H.

Rule Three: Other position holders are mapped as follows:

Level 2 Includes

- Society represented supervisors
- Management Band 17-I supervisors
- Society Purchaser and Supervisory Purchaser Power Workers Union (PWU) for Element 7.2
- Society represented Investment Recovery staff for Element 8.1
- Traders and Real-Time Markets Supervisor for Element 12 authorities

Level 1 includes

- PWU represented supervisors
- Management Band 17-J supervisors
- First Line Management Assistant (FLMa)
- Non-Supervisory PWU Purchaser for Element 7.2
- Developmental Traders for Element 12 authorities

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1.3 Authorities Delegated to All Position Holders

Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
1.1	**Projects and Investments – In Budget** Approve; Amend Scope; Amend Cost Estimate; Defer; Cancel (includes approval of cost transfer to current operations) Approvals are governed by OPG-STD-0076 Developing and Documenting Business Cases. Projects are defined and governed by FIN-PROC-0030 Property, Plant and Equipment.	$40M	$20M	$10M	$5M	$2M	N/A	N/A	N/A	>$200K Per OPG-STD-0076
1.2	**Projects and Investments – Not in Budget** Includes projects identified in the business plan for a future year that are being advanced by >1 year to the current year. See Element 1.1 for inclusions and governance requirements.	$40M	$10M	$5M	$2.5M	$1M	N/A	N/A	N/A	>$200K Per OPG-STD-0076
1.3	**Business Development** Approve; Amend Scope; Amend Cost Estimate; Defer; Cancel (includes approval of cost transfer to current operations) Initial project or contract for a subsidiary or joint venture. A series of projects implementing a decision previously approved under this Element can be approved under Elements 1.1 or 1.2. Approvals are governed by OPG-STD-0076 Developing and Documenting Business Cases. If doing business through a joint venture or a wholly owned subsidiary where OPG has an ownership interest refer to OPG-STD-0093 Joint Venture Governance and OPG-STD-0094 Wholly-Owned Subsidiary Governance for certain approvals noted therein. For approvals not identified in those governance documents, Element 1.3 for initial project or contract approval shall apply and Element 1.10 for on-going project or contracts shall apply, as applicable.	$20M	$1M (SVP Corp Bus Dev only)	N/A	N/A	N/A	N/A	N/A	N/A	Per OPG-STD-0076
1.5	**Requisitions and Payment Requisitions** Approvals governed by OPG-PROC-0060 Requisitioning Items and Services and OPG-PROC-0051 Payment Procedure.	>$40M	$40M	$20M	$10M	$5M	$2M	$50K	$10K	N/A

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Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
1.5-DAM	**Requisitions – *Darlington Aging Management* (DAM)** Approvals governed by OPG-PROC-0060 Requisitioning Items and Services. *CEO approval not required for requisitions for which an approval was obtained under elements 1.1 or 1.2 specifically relating to Darlington refurbishment projects under the scope of funds approved for release by the OPG Board.	>$100M*	$100M*	$50M	$10M	$5M	$2M	$50K	$10K	ALL
1.6	**Business Travel and Expense and Employee Relocation Interim Expenses** BT&E approvals governed by OPG-STD-0075 Business Travel and Expenses. External training >$10K requires pre-approval by an Enterprise Leadership Team member.	>$100K	$100K	$40K	$25K	$15K	$10K	$5K	N/A	N/A
1.7	**Declare Asset Surplus** Approvals governed by OPG-PROC-0081 Disposal of Surplus Assets; and one of: FIN-PROC-0030, Property, Plant and Equipment or FIN-PROC-0031 Fuel Inventory and Materials and Supplies Inventory Accounting	$10M	$7.5M	$5M	$2M	$500K	$250K	N/A	N/A	>$250K
1.8	**Non-Charitable Research Funding and Collaboration Contracts/Agreements** Information exchange agreements require consultation with Law Division.	>$10M	$10M	$5M	$2M	$1M	N/A	N/A	N/A	>$500K

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Title:
ORGANIZATIONAL AUTHORITY REGISTER

Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
1.10	**Non-Energy Sales (excludes core electricity transactions)** Contracts/Agreements >$5M require consultation with stakeholders including Law Division, Investment Planning, Corporate Risk Management – Credit Risk, Treasury, Insurance and Risk Management, Controller and Taxation. Contracts up to $5M and outside the normal course of business (such as deviations from standard contract terms & conditions and work performed by OPG as part of international transactions) for a business unit also require consultation with stakeholders including Law Division, Corporate Risk Management – Credit Risk, Treasury, Insurance and Risk Management, Site Controller and Taxation, as appropriate. See Section 1.6 for specific Joint Venture and Subsidiary transaction approval requirements. If doing business through a joint venture or a wholly owned subsidiary where OPG has an ownership interest refer to OPG-STD-0093 Joint Venture Governance and OPG-STD-0094 Wholly-Owned Subsidiary Governance for certain approvals noted therein. For approvals not identified in those governance documents, Sections 1.3 and 1.6 apply, as applicable. Invoices are governed by OPG-PROC-0026 Invoicing Procedure. Commercial Services approvals are governed by COE-PROG-0001 Isotope Sales.	>$40M	$40M	$25M	$10M	$5M	$50K	N/A	N/A	Refer to the transaction description column for Finance review thresholds
1.11	**First Nation and Métis Capacity Development** Secondary approval for amounts <$100K and recommendation for those >$100K required by Director, First Nations and Métis Relations. Approvals governed by OPG-STD-0087 Management of First Nations and Métis Relations	>$500K	$500K	$500K	$250K	$100K	N/A	N/A	N/A	All Transactions

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Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
1.12	**Settlement of Legal Proceedings** Settlement of all legal proceedings requires concurrence of Law Division. Concurrence of SVP Law, General Counsel & Chief Ethics Officer required for all settlements > $250,000. (For settlements relating to legal proceedings involving Aboriginal groups, Element 14.1 Aboriginal Settlement Agreements governs. For settlement of legal proceedings relating to claims for which OPG has insurance, Treasury Organizational Authority Register FIN-STD-0004, element 10.5.1 governs.)	>$500K	$500K	$500K	$250K	$100K	N/A	N/A	N/A	N/A
1.13	**Non-Disclosure/Confidentiality Agreements**	Unlimited				N/A	N/A	N/A	N/A	N/A
7.3	**Low Dollar Purchases** Approvals governed by OPG-PROC-0051 Payment Procedure; OPG-PROC-0060 Requisitioning Items and Services; and OPG-PROC-0064 Purchasing Card.	Applies to management and supervisory staff; *Expeditors* and purchasing card holders. Up to $10K per transaction								N/A

1.4 Authorities Restricted to Specific Organizations

Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
2.1	**Charitable and Not for Profit Donations** Restricted to Corporate Relations & Communications.	>$25K	$25K	N/A	$25K	$10K	N/A	N/A	N/A	>$200K
2.2	**Sponsorships for Brand building** Restricted to Corporate Relations & Communications.	>$200K	$200K	N/A	$50K	$50K	N/A	N/A	N/A	>$200K
2.3	**Requisitioning of Advertising** Advertising other than for vacancies or surplus asset sales. Restricted to Corporate Relations & Communications.	>$6M	$6M	N/A	$2M	$1M	N/A	N/A	N/A	N/A

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Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
4.1	**Requisitioning of Legal Services** Approvals governed by LAW-PROC-0001 Acquiring Outside Legal Services. Restricted to Law Division.	>$4M	$4M	N/A	$2M	$1M	N/A	N/A	N/A	N/A
5.0 Authority to Implement Decision where Prior Approval Exists										
5.2, 5.6, 5.8 Statutory and Mandated Payments see: OPG-PROC-0051 Payment Procedure for Vendor Invoices and Statutory Payments										
5.1	**Approved Bulk Payroll Transactions** Restricted to Total Rewards and Solutions Centre	>$200M	>$200M	N/A	>$200M	$100M	$100M	N/A	N/A	N/A
5.1.1	**Approved Individual Employee Payroll Transactions** Restricted to Total Rewards and Solutions Centre	>$3M	>$3M	N/A	>$3M	$3M	$3M	$300K	$300K	N/A
5.4	**Individual Relocation Assistance Payments** Restricted to Real Estate Services.	>$1M	>$1M	N/A	>$1M	$400K	$200K	N/A	N/A	N/A
5.9	**Disbursement to the Nuclear Waste Management Organization** (NWMO) Monthly cash disbursement to the NWMO.	Up to the annual budget approved by the NWMO Board for services and product related to the low and intermediate level waste deep geologic repository (L&ILW DGR), Adaptive Phased Management (APM), and Lifecycle Liability Management (LLM) programs has been assigned to VP Finance, Chief Controller & Accounting Officer.								
6.1	**Requisition Fuel**	SVP or higher unlimited within business plan								
6.2	**Purchase/Sale of Fuel; Water Rental Agreements; Emission Reduction Credits/Allowances** Approval covered by other governance including: N-PROC-MM-0040 Nuclear Fuel, EM-PROC-0022 Energy Markets Fuel Procurement Activities and OPG-STD-0072 Credit Risk Management Standard	>$200M	$200M	$200M	$50M	$25M	$15M	$5M	N/A	>$5M
7.2	**Procurement Contracts** Approvals governed by OPG-PROC-0058 Procurement Activities or LAW-PROC-0001 Acquiring Outside Legal Services. Restricted to Supply Chain and Law Division. * Contracts >$5M require secondary review by Finance. *Contracts >$20M require secondary approval by the CFO. *Contracts >$40M require secondary approval by the CFO and CEO. Non-intent changes to contract Purchase Order (PO) language with no financial impact and no change to allocation of risk between OPG and the counterparty do not require secondary sign-off by CFO/CEO.	>$40M	>$40M*	>$40M*	$40M*	$15M	$3M	$1M	$500K	>$5M

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Element	Transaction	Delegated Authority								Finance Review Required
		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
7.2-DAM	**Procurement Contracts – *Darlington Aging Management*** Approvals governed by OPG-PROC-0058 Procurement Activities. Restricted to Supply Chain and Business & Admin. Services BAS) ELT member. Non-intent changes to contract PO language with no financial impact and no change to allocation of risk between OPG and the counterparty do not require secondary sign-off by CFO/CEO. * Contracts >$5M require secondary review by Finance. *Contracts >$50M, other than those related to approved Darlington Refurbishment projects, require secondary approval by the CFO. *Contracts >$100M, other than those related to approved Darlington Refurbishment projects, require secondary approval by the CFO and CEO. *Secondary CEO/CFO sign-off not required for contracts for which an approval was obtained under elements 1.1 or 1.2 specifically relating to Darlington refurbishment projects under the scope of funds approved for release by the OPG Board.	>$100M*	>$100M*	>$100M*	$100M*	$15M	$3M	$1M	$500K	>$5M
8.1	**Sale/Disposal of Assets** Approvals governed by OPG-PROC-0081 Disposal of Surplus Assets. Restricted to Investment Recovery.	$25M	$15M	$15M	$4M	$2M	$1M	$500K	N/A	>$500K
9.1	**Acquire, Lease, Manage, and Dispose of Real Estate Rights and Interests and Related Transactions** Approvals are governed by approved Real Estate procedures, and OPG-STD-0076 Developing and Documenting Business Cases for projects >$200K. Restricted to Real Estate. Extensions to relocation benefits time period shall be approved by the SVP for Real Estate.	>$10M	$10M	N/A	$5M	$1M	$500K	$250K	N/A	>$5M for non-projects; Projects >$200K Per OPG-STD-0076
9.2	**Home Purchases and Purchase Guarantees** Restricted to Real Estate	>$2M	$2M	N/A	$1.5M	$1M	$500K	$250K	N/A	>500K
10	**Treasury authorities are documented in FIN-STD-0004 Treasury Organizational Authority Register**									

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		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
11.1	**Customer/Vendor Refunds, Credits and Adjustments** Approvals governed by OPG-PROC-0026 Invoicing Procedure and OPG-PROC-0051 Payment Procedure. Restricted to Shared Financial Services, Corporate Functions Controllership and Credit Risk.	>$2M	$2M	N/A	$1.5M	$1M	$500K	$50K (AP only)	$10K (AP only)	N/A
11.3	**Asset Adjustments** Approvals governed by FIN-PROC-0030 Property, Plant and Equipment and FIN-PROC-0031 Fuel Inventory and Materials and Supplies Inventory Accounting. Restricted to Finance.	>$10M	$10M	N/A	$5M	$2.5M	$1M	$0.5M	N/A	N/A
12.1	**Electricity Products, Derivatives and Services – Enabling Agreements** Includes confidentiality or similar agreements involving information on energy products and services. Excludes establishing specific product, price or quantity commitments. Approvals governed by OPG-PROG-0016 Credit and Market Risk Management Program and restricted to Commercial Contracts & Power Marketing.	Unlimited				N/A	N/A	N/A	N/A	N/A
12.2	**Domestic and Interconnected Trading and Origination Activity; Options and Derivatives** – Restricted to Commercial Contracts & Power Marketing									
12.2.1	Current Day (Real Time)	>1,500 MW	>1,500 MW	N/A	1,000 MW	800 MW	800 MW	800 MW	N/A	N/A
12.2.2	Current Month (plus following when past mid-month)					700 MW	500 MW	300 MW	N/A	N/A
12.2.3	Hydro Quebec Segregated Transactions (Real and Current Month)					700 MW	550 MW	500 MW	N/A	N/A
12.2.4	**Term from Deal Entry Date**	5 years >1,000 MW	5 years 1,000 MW	N/A	5 years 600 MW	5 years 500 MW	3 years 300 MW	2 years 100 MW	≤1 year 50 MW	N/A
12.3	**Ontario Hourly Bidding/Offering Activity** Restricted to individuals with a valid digital certificate and authorized by the Director, Market Operations. Applied to the quantity committed in each hour to the specific administered market and independently to the administered market and to the position with authority to engage in bids/offers in that market.	OPG Installed Capacity							As Assigned	N/A

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		CEO	ELT Member	SVP	Management Band			Authority Level		
					D/E	F	G/H	2	1	
12.4	**Domestic Sale of Independent Electricity System Operator Defined Ancillary Services** Restricted to Commercial Contracts & Power Marketing.	> $48M	$48M	N/A	$12M	$6M	$3M	$1.5M	N/A	N/A
12.5	**Other Electricity Products, Derivatives and Services** Restricted to Commercial Contracts & Power Marketing.	> $32M	$32M	N/A	$8M	$4M	$2M	$1M	N/A	N/A
12.5.1	**Physical Transmission and Financial Transmission Rights** Restricted to Commercial Contracts & Power Marketing.	> $32M	$32M	N/A	$8M	$5M	$1M	$500K	N/A	N/A
12.6	**Long Term Electricity Supply Contracts [e.g., Hydroelectric Supply Agreements(HESA)]** Initial contract/agreement restricted to Commercial Contracts & Power Marketing.	All	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Investment Planning
12.6.1	**Long Term Electricity Supply Contracts (e.g., HESA)** Subsequent modifications impacting economics to OPG of the agreement. Restricted to Commercial Contracts & Power Marketing.	> $32M	$32M	N/A	$8M	$4M	$2M	$1M	N/A	>$8M Investment Planning
14.1	**Aboriginal Settlement Agreements** (If settlement agreement involves a legal proceeding, the concurrence of SVP Law, General Counsel & Chief Ethics Officer is also required.)	$5M	N/A	N/A	N/A	N/A	N/A	N/A	N/A	ALL

1.5 Personnel Approvals

Apply to all Management and Supervisory Position Holders	• Timesheets and exceptions (Band F and above may delegate approvals to Administrative/Executive/Support Assistants)	R1
	• Appointments, Terminations, Setting/Changing Rate Classification – for represented staff within Collective Agreement and HR governance parameters, non-represented staff within standard provisions • Leave of Absence (without pay >3 months, with pay >5 days)	R2

2.0 ROLES AND ACCOUNTABILITIES

2.1 Chief Executive Officer

Approves delegation of CEO authorities.

2.2 Position Holders

Comply with authority limits and specifications.

2.3 Site Controller/Local Finance Manager

Responsible for implementation of the OAR and providing advice to staff.

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Darlington Aging Management: Darlington projects and investments that have been approved with a business case based on OAR Element 1.1, 1.2 or 1.3. This would include station, refurbishment and project portfolio investments that address the physical aging and obsolescence of structures, systems and components, as well as regulatory investments and improvements, required to support plant Life Extension past normal end of life, including “Blue Ribbon” and integrated improvement Program investments.

Expeditor: Delegated by Supply Chain to designated non-Supply Chain individuals to allow purchasing for pre-approved non-PCard transactions up to $10K.

Rule of One (R1): Position holder approves items relating to a direct report.

Rule of Two (R2): Position holder approves items relating to a direct report of a direct report.

3.2 Abbreviations and Acronyms

BAS	Business & Admin. Services
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DAM	Darlington Aging Management
ELT	Enterprise Leadership Team
FLMa	First Line Management Assistant
HESA	Hydroelectric Supply Agreement
NWMO	Nuclear Work Management Organization
OAR	Organizational Authority Register
PO	Purchase Order
PWU	Power Workers Union
SVP	Senior Vice President

4.0 BASES, RECORDS AND REFERENCES

4.1 Bases

None

4.2 Records

None

4.3 References

4.3.1 Performance References

Governance required for specific approvals is referenced with the Element approval limits and in Section 1.6.

4.3.2 Developmental References

None

5.0 REVISION SUMMARY

This is an **intent** revision.

- Element 1.9 removed as OPG-PROC-0081Investment Recovery: Disposal Of Surplus Assets has been revised and no longer allows for local sale of surplus assets/materials

ONTARIO POWER GENERATION

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Standard

TITLE
DEVELOPING AND DOCUMENTING BUSINESS CASES

PURPOSE
This Standard describes the minimum requirements for developing and gaining approval for investments and provides a description of required information to be included in a *Business Case Summary* (*BCS*).

EXCEPTIONS
None

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Title:
DEVELOPING AND DOCUMENTING BUSINESS CASES

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Standard

Title:
DEVELOPING AND DOCUMENTING BUSINESS CASES

1.0 DIRECTION

Business Case Summaries (*BCS*) shall be prepared in order to provide a concise summary of the business need, alternatives considered, economic evaluation, proposed solution, and the benefits and risks of a proposed investment. *BCS* approval releases a specific level of funding to achieve specific results in terms of scope, schedule, and cost, with an understanding of the associated risks. *BCSs* are also used as evidence of prudent decision making for regulatory purposes.

Business case development and documentation shall be scaled appropriately according to the nature and the level of investment. Three classes of investments and the corresponding three types of required documentation for a *BCS*, ranging from a simple form to a more detailed document, are defined depending on the nature, size, complexity, and risks of the proposed investment.

1.1 Overview

This Standard describes the minimum requirements for developing, documenting, and gaining approval of business cases for all investments. While the focus is on investments in projects, the Standard also applies to other business investment decisions, including mergers, joint ventures, acquisitions, and life cycle asset investment decisions such as major re-investments, refurbishments, and life extensions.

This Standard does not specify the activities to be carried out by the *Project Sponsor* and Project Executing Authority to ensure that appropriate front-end project development and stakeholder consultations are performed. These requirements are specified in Business Unit (BU) Project Management Governance. See Appendix A for a schematic of where this Standard fits in the context of related investment governance.

1.2 Needs Statement and Classification of Investments

Each business investment decision requires a needs statement. The need can arise in one of the following ways:

(a) **Sustaining Investments** to maintain facilities and equipment, to address potential or realized performance gaps (operational performance worse than target).

(b) **Regulatory Investments** to ensure compliance with new or changed regulations, thereby enabling continued operation of the facility.

(c) **Value Enhancing Investments** to reduce cost or increase revenue, or both, through improvements such as increased capacity, availability, or efficiency. Value Enhancing investments require a financial evaluation of the proposed alternative to demonstrate the added value.

(d) **Business Development Initiatives** to be explored or pursued, which include, but are not limited to:

- Asset development initiatives such as major plant rehabilitation, plant life extensions, new developments, redevelopments, and closures.

- Major acquisitions, mergers, divestitures, business ventures with partners; any significant departure from established strategies of the Corporation.

- Asset sales/swaps.

- New product development including participation in newer markets or products not previously approved.

1.3 Project Phases and Business Case Summaries

All Ontario Power Generation (OPG) projects progress through the phases of Identification, Initiation, Definition, Execution, and Close-Out utilizing the gated approach to project progression. During each of the Investment/Project Phases, Partial, Full, or Superseding *BCS* Releases may be utilized. Appendix B provides an overview of *BCS* documentation associated with different project phases and releases.

During the Identification Phase, to meet the requirements for Business Planning, Planning *BCSs* (to be documented on **OPG-FORM-0102, Planning Business Case Summary**) or equivalent document such as Asset Investment Screening Committee (AISC) Part A, are developed to list the project in the BUs Project Portfolios. If sufficient information is available during Business Planning, a Type 1 *BCS* (see Section 1.4.1) may be used in place of a Planning *BCS*.

Simple projects may require only one subsequent *BCS* to the Planning *BCS* in order to complete all of the Initiation, Definition, and Execution Phase work.

More complex projects may require a single *BCS* to complete the work up to the end of the Definition Phase, before seeking further *BCS* approvals to complete the work of the Execution Phase.

Very complex projects, in particular Business Development Initiatives, may require multiple releases within each of the Initiation, Definition, and Execution Phases of the project. This approach helps manage risk by applying lessons learned during each project phase, to improve project performance during subsequent phases.

All projects also require a *Post-Implementation Review* (*PIR*) **[R-4]** Plan.

Project cost estimates shall include appropriate contingency given the quality of the estimate. If known, the estimate class of the cost estimate shall be stated.

For capital additions, capitalization of expenditures normally begins at the Definition Phase of the project when the selected alternative has been determined and work is being done to progress that selected alternative (see Property, Plant and Equipment Standard **[R-6]**).

1.4 Scaled Documentation

BCS documentation and approval requirements are driven by the nature of work to be executed through the proposed investment/project, and the estimated cost of the investment/project.

If a project is not listed on the BU/Corporate Function's project portfolio for the year in the current Business Plan (e.g., not on the current year's Approved New Starts List in Nuclear), it is considered **emergent** and shall be documented using at least Type 2 documentation to ensure proper documentation of the justification for the preferred alternative.

This Standard defines three levels of *BCS* documentation described in Sections 1.4.1, 1.4.2 and 1.4.3 and summarized in Table 1.

1.4.1 Type 1 Documentation

Type 1 Documentation applies to Sustaining and Regulatory investments/projects less than $10 M, which meet all risk criteria for Type 1 Documentation as shown in Table 1, and which are not emergent.

Investments/projects that meet Type 1 criteria for documentation may utilize a single *BCS* to cover all of the Initiation, Definition, and Execution phase work, if practical. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

Since the alternatives for investments/projects that meet the Type 1 criteria have been already assessed in an *LCP* (or equivalent document), or if there are no reasonable alternatives available, there is typically no need to justify the chosen alternative in the *BCS* write-up. If justification is available (e.g., in an *LCP*), the *BCS* may refer to it.

Investments/projects that meet the Type 1 documentation criteria shall be documented on **OPG-FORM-0074, Type 1 Business Case Summary**. Guidance on the use of the form is included in the form.

1.4.2 Type 2 Documentation

Type 2 Documentation applies to:

- Sustaining and Regulatory investments/projects greater than or equal to $10 M but less than $25 M, which meet all risk criteria for Type 2 Documentation as shown in Table 1, and which are not emergent
- Value Enhancing investments/projects less than $25 M, which also meet all risk criteria for Type 2 Documentation, and which are not emergent, and
- Emergent Sustaining, Regulatory, or Value Enhancing investments/projects less than or equal to $5 M, which meet all risk criteria for Type 2 Documentation.

Investments/projects that meet Type 2 criteria for documentation may utilize a single *BCS* to cover all of the Initiation, Definition, and Execution phase work, if practical. Because of the complexity of these projects, it is likely that one or more *BCSs* will be required to progress the project to the end of the Definition Phase, and one or more *BCSs* may be required for the Execution Phase. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

Investments/projects that meet the Type 2 documentation criteria shall be documented on **OPG-FORM-0075, Type 2 Business Case Summary**. Guidance on the use of the form is included in the form.

1.4.3 Type 3 Documentation

Type 3 Documentation applies to:

- All Business Development Initiatives,
- Sustaining, Regulatory, and Value Enhancing investments/projects greater than or equal to $25 M
- Sustaining, Regulatory, and Value Enhancing investments/projects less than $25 M, which do not meet all the risk criteria for Type 1 and Type 2 Documentation as shown in Table 1
- Emergent Sustaining, Regulatory, and Value Enhancing investments/projects greater than $5 M, and
- Emergent Sustaining, Regulatory, and Value Enhancing investments/projects less than or equal to $5 M which do not meet all the risk criteria for Type 2 Documentation.

Investments/projects that meet Type 3 criteria for documentation are normally complex undertakings with long timelines and a significant degree of risk, and often require a phased approach to project development and approvals. Multiple releases of funds are often required for each Phase (Initiation Phase, Definition Phase, and Execution Phase). A comprehensive risk assessment must also be completed for each release, and documented in each *BCS*. This approach helps manage risk by applying lessons learned during each project phase, to improve investment/project performance during subsequent phases. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

If the only criterion which is requiring an investment/project to utilize Type 3 *BCS* documentation is the estimated total project cost, the investment/project may utilize Type 2 *BCS* documentation for the Initiation and Definition Phase releases, provided that the cumulative release amount (including committed spending) is less than $25 M. However, the Sponsor may still request Type 3 *BCS* documentation, if deemed more appropriate. Such a project shall utilize Type 3 *BCS* documentation for all releases which include Execution Phase work.

Investments/projects that meet the Type 3 documentation criteria shall be documented on **OPG-FORM-0076, Type 3 Business Case Summary**, which consists of an Executive Summary and Recommendations section, followed by the main body of the *BCS* and Appendices. Guidance on the use of the form is included in the form.

Table 1 provides a summary of the general and risk criteria for deciding on the *BCS* documentation requirements. See also Appendix C for a decision flowchart to determine which type of *BCS* documentation applies.

Table 1: Summary of Scaled Documentation Criteria and Documentation Requirements

General Criteria	Type 1	Type 2	Type 3
Investment Class	Sustaining, Regulatory	Sustaining, Regulatory, Value Enhancing	Sustaining, Regulatory, Value Enhancing, Business Development Initiative
Total Estimated Cost (*Emergent Projects*)	Not Applicable	≤ $5 M	> $ 5M
Total Estimated Cost (Listed Projects)	< $10 M	≥ $10 M but < $25 M	≥ $25 M
Risk Criteria	**Type 1**	**Type 2**	**Type 3**
Design Complexity	Minimal and simple; and uses technology that is proven or previously used.	Uses proven technology or methodology.	Does not meet Type 1 or Type 2 risk criteria.
Fabrication and Installation Risk	Requires simple processes.	Uses readily available processes and technology.	
Safety Risks	Not expected to introduce new safety (personnel, nuclear, or dam), fire, seismic, environmental, physical security or cyber/Information Technology (IT) security, or production risks.		
Modification Risk	Not an installation of a new station system, sub-system, or a significant change to existing systems.		
Schedule Risk	Sufficient float to ensure that any regulatory commitments and preparations for planned outage will be made on schedule.		
Documentation Requirements	**Type 1**	**Type 2**	**Type 3**
Alternative Analysis	Justification for preferred alternative already documented elsewhere, or no reasonable alternatives to the proposed solution.	Justification of the preferred alternative required.	
Financial Evaluation	Not Required	Required for Value Enhancing and Business Development Initiative and updated for each release. Optional for Sustaining and Regulatory.	

1.5 Over-Variances and Superseding Releases

Investments/projects that require a cost or schedule over-variance approval, where there is no material change in scope, may utilize **OPG-FORM-0077, Project Over-Variance Approval**. Whether or not a scope change is considered material is left to the judgement of the *Project Sponsor*. The Project Over-Variance Approval form should not be used for over-variances in excess of 20% of cost or schedule or both.

Superseding Releases shall be used for investments/projects that encounter a material scope change, a significant change in the financial evaluation, or an over-variance in excess of 20% of cost or schedule or both. The type of *BCS* documentation of these superseding releases shall reflect the new costs and risk criteria.

For project deferrals, a memorandum, signed by the original *BCS* line approver, shall be used. This memorandum should document: (i) the rationale for the project deferral and its implications with respect to regulatory, health and safety, and economic targets in the original business case; (ii) when the project is expected to resume; (iii) any expected cost variance, annual cash flow impacts relative to the approved business case cash flows, and the expected accounting impacts; and (iv) alternatives to project deferral considered and the reasons why these were not selected.

2.0 ROLES AND ACCOUNTABILITIES

2.1 Approval and Review Accountabilities

For all *BCS* Types, project funding releases are to be approved in accordance with Elements 1.1 Projects and Investments – In Budget, 1.2 Projects and Investments – Not in Budget, or 1.3 Business Development Initiatives of the Organizational Authority Register (OAR) **[R-3]**.

All *BCS* Types require three signatures: (1) Recommended by; (2) Finance Approval; and (3) Line Approval (per OAR **[R-3]**). Project funding releases requiring Board approval shall have a *BCS* approved by the CFO, prior to a recommendation being submitted to the Board for approval.

2.1.1 Line Approval

For Initiation and Definition Phase *BCSs*, Line Approval authority applies to the cumulative total cost of work being committed, not the estimated total investment/project cost.

For *BCSs* that cover Execution Phase work, Line Approval authority applies to the estimated total investment/project cost (including contingency), plus any relevant incremental ongoing costs to which OPG is also committed as a result of the investment/project.

Table 2: BCS Signature Block

Recommended by	BU Head/ ELT Member	BU Head/ ELT Member	Project Sponsor	Project Sponsor	Project Sponsor	Project Sponsor
Finance Approval	← - - - - - - - - - - - - - - - See Finance Approval in Table 3 - - - - - - - - - - - - - - - →					
Line Approval*	Board	CEO	ELT Member	SVP	Band D/E	Band F

* If Line Approval authority's position matches more than one category, the highest ranked category will apply; e.g., an SVP who is also an ELT Member shall follow the "ELT Member" Line Approval OAR authority.

2.1.2 Finance Approval

Finance Approvals are shown in Table 3.

Table 3: Finance and Line Approvals for BCSs Corresponding to OAR

Line Approval	Board	CEO	ELT Member	SVP	Band D/E	Band F
Finance Approval						
Nuclear	CFO*	CFO*	VP Nuclear Finance	Director Controllership Nuclear Finance	Director Controllership Nuclear Finance	Finance Controller Nuclear Finance
Hydro/Thermal	CFO*	CFO*	VP HTO Finance	N/A	Plant Group/ Station Controller	Plant Group/ Station Controller
Corporate Functions (incl. Corporate Office, BAS, Finance, People and Culture, Law Division, and Commercial Operations and Environment)	CFO*	CFO*	VP Finance, Chief Controller	N/A	Director Controllership Corporate Functions Controllership	Finance Controller Corporate Functions Controllership

* Staff support for the CFO is provided by Controllership for all Sustaining and Regulatory projects and Investment Planning for Value Enhancing, Destiny, Business Development, life extension/reduction, as well as R/R/R (Retirement/Rehabilitation/Redevelopment) projects.
Investment Planning also provides staff support to the CFO for review of investment decisions involving major contracts (e.g., IT services contracts, labour contracts, energy supply agreements, long term leases).

2.1.3 Over-Variance Approval

Investment/project over-variances require approval by the original approval authority as per the OAR **[R-3]**. If the over-variance results in the total actual and committed cost to date (for *BCSs* up to and including Definition phase work) or the total project cost (for *BCSs* that cover Execution Phase) exceeding the approval limit for the original approval authority, higher approval authority is required to approve the over-variance.

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Business Case Summary (BCS): A summary document that provides sufficient information for decision-makers to evaluate, rank, and approve or reject an investment.

Emergent Project: An investment/project that is not on the BU/Corporate Function's project portfolio for the year in the current Business Plan.

Life Cycle Plan (LCP): A facility LCP is an operation, maintenance, and investment plan that is intended to maximize the value of the facility. The LCP is consistent with corporate strategic direction, based on the facility Condition Assessment and a consideration of the alternatives and risks involved.

Post-Implementation Review (PIR): A systematic performance evaluation of a fully or partially completed project to assess the benefit realization of the project and to capture the lessons learned.

Project Sponsor: The individual responsible for:

(a) Developing and approving the project charter.
(b) Setting the project objectives and priorities.
(c) Obtaining funding approval.
(d) Monitoring project execution including resolving conflicts and problems.
(e) Managing related risks.

3.2 Abbreviations and Acronyms

AISC - Asset Investment Screening Committee
BAS - Business and Administrative Services
BCS - Business Case Summary
BP - Business Plan
BU - Business Unit
CEO - Chief Executive Officer
CFO - Chief Financial Officer
ELT - Enterprise Leadership Team
IT - Information Technology
LCP - Life Cycle Plan
OAR - Organizational Authority Register
OPG - Ontario Power Generation
PIR - Post-Implementation Review
SVP - Senior Vice-President
VP - Vice-President

4.0 RECORDS AND REFERENCES

4.1 Records

The original approved *BCS* along with its supporting documentation is to be held by the Project Sponsor. Refer to the Records File Information on the BCS forms and the Project Over-Variance Approval form for record filing.

4.2 References

4.2.1 Performance References

- OPG-FORM-0074, Type 1 Business Case Summary.
- OPG-FORM-0075, Type 2 Business Case Summary.
- OPG-FORM-0076, Type 3 Business Case Summary.
- OPG-FORM-0077, Project Over-Variance Approval.
- OPG-FORM-0102, Planning Business Case Summary.
- OPG-PROC-0056, Post-Implementation Review.

4.2.2 Development References

[R-1] OPG-PROG-0006, Investment Management.
[R-2] OPG-PROC-0055, Life Cycle Plan Procedure.
[R-3] OPG-STD-0017, Organizational Authority Register.
[R-4] OPG-PROC-0056, Post-Implementation Review.

[R-5] OPG-PROG-0004, Enterprise Risk Management.
[R-6] FIN-STD-0006, Property, Plant and Equipment.

5.0 REVISION SUMMARY

This is an Intent revision.

- Updated *BCS* documentation criteria for *emergent* projects to allow utilizing Type 2 BCS form for emergent projects less than or equal to $5 M. Updates were performed in Section 1.4 and Appendix C.
- Clarified criteria for classifying emergent projects in Section 1.4.
- Clarified *BCS* requirement for Board approvals in Section 2.1.
- Updated Finance Approval table in Section 2.1.2.
- Updated Development References in Section 4.2.2 and Document Relationships in Appendix A.

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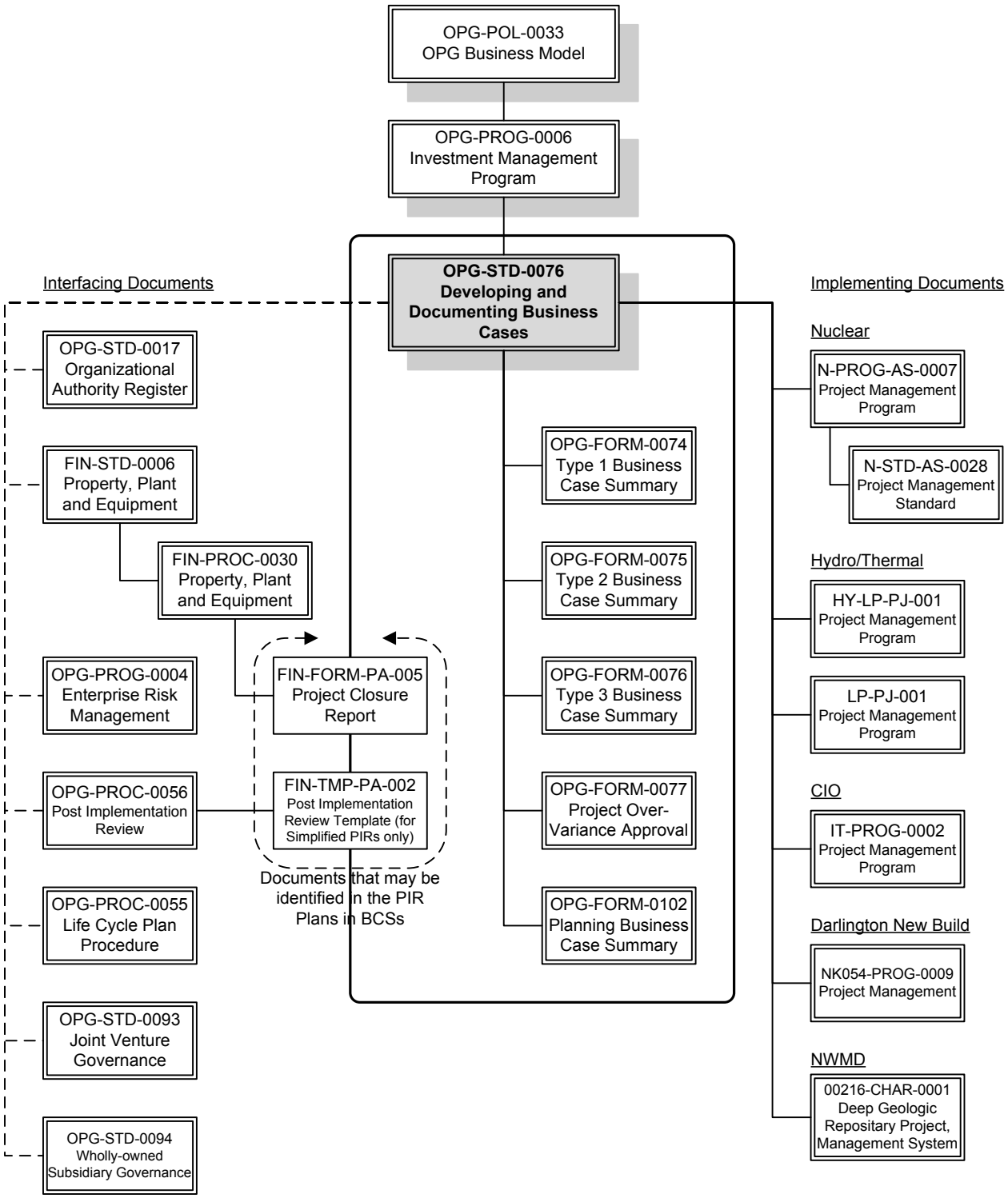
Title:
DEVELOPING AND DOCUMENTING BUSINESS CASES

Appendix A: Document Relationships



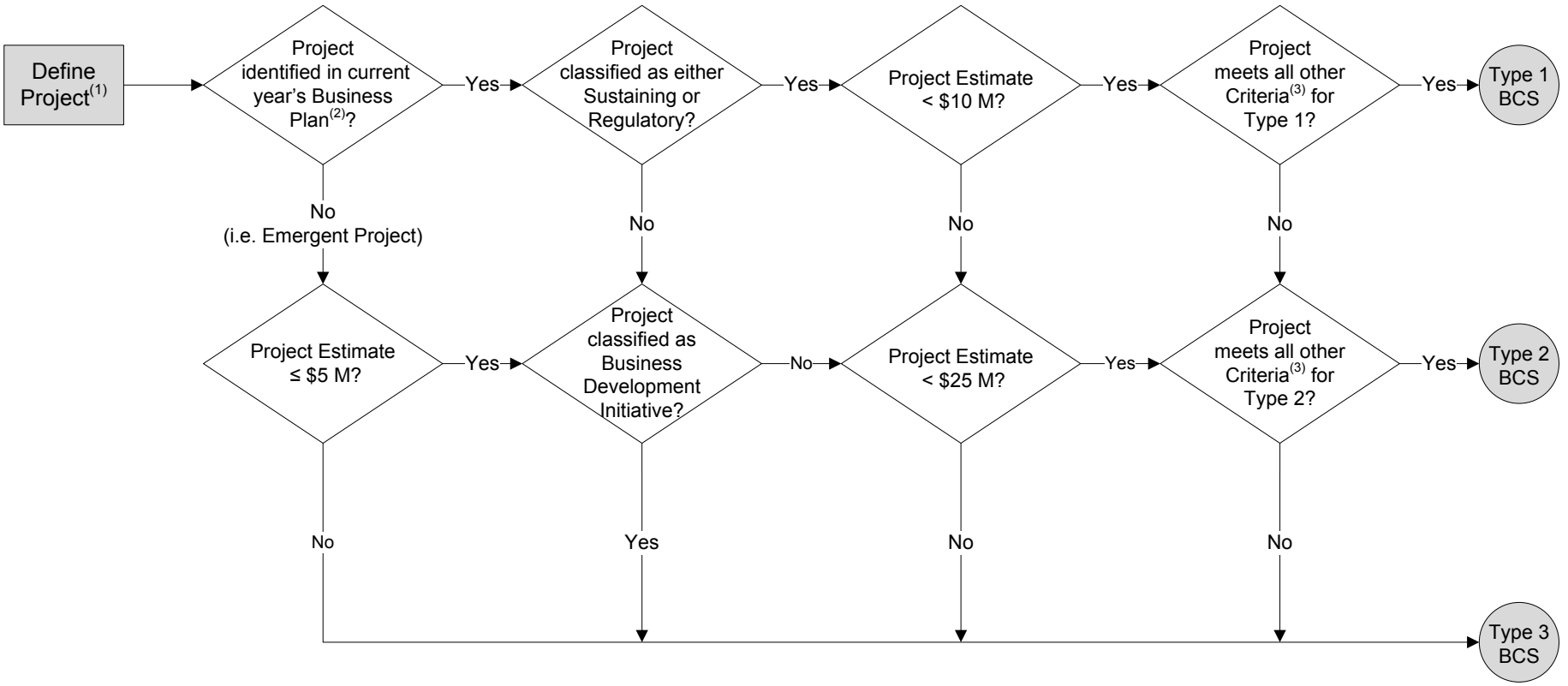
Appendix B: Overview of Potential Business Case Summary Documentation at Different Project Phases

Business Case Summaries Which May Be Completed At Each Project Phase				
Project Phases per Project Development Protocol	**Identification**	**Initiation**	**Definition**	**Execution**
Description of Work	Identification and screening of a business concept or opportunity	Evaluation of a selected number of alternatives and selection of the preferred alternative	Development and definition of the preferred alternative	Delivery of the preferred alternative
BCS Required to Enter Project Phase	Planning *BCS* or AISC Part A	**Initiation Phase BCS**	**Definition Phase BCS**	**Execution Phase BCS**
Partial Release		**Used only if Phase needs to be performed in stages.** (Multiple partial releases are allowable)		**Used only if Execution Phase work needs to be performed in stages** (e.g., to sign execution contracts for execution on initial phase/unit in a multi-phase/multi-unit project)
Full Release		Full release for **Initiation Phase Work**	Full release for **Definition Phase Work** (Simpler projects may use a Full Release Definition Phase *BCS* for all of the Initiation and Definition Phase work)	Full release for **Execution Phase Work** (Very simple projects may use a Full Release Execution Phase *BCS* for all of the Initiation, Definition and Execution Phase work)
Superseding Release		**Used on an exception basis only** Re-issued *BCS* with analysis justifying suspension, cancellation, or continuation of work **for the applicable Phase** following a material scope change, material schedule change, or material cost overrun(1)		
Approval Authority Level for Funding Releases (OAR)	Funding identified in Sponsoring BU's Approved BP/Budget	Based on **cumulative cost of work being committed** (i.e., including cancellation and demobilization costs); subject to limits in OAR *(Note: OAR approval level should be set based on total estimated project value, if work being committed in these phases effectively commits OPG to the total project)*		OAR Approval based on **estimated total cost of project**
Typical Funding Source for Capital Projects	OM&A	OM&A(2)	Capital	Capital

(1) In case of cost overruns less than or equal to 20%, the Project Over-Variance Approval Form OPG-FORM-0077 shall be used, rather than a Superseding *BCS*. An updated financial analysis shall be provided for Value Enhancing projects. Refer to Section 1.5, Over-Variances and Superseding Releases for details.

(2) Where a major project already has an approved Definition Phase release (and hence is being capitalized), expenditures on Initiation Phase work of sub-projects of that major project can also be capitalized, as these expenditures are funded under the Definition Phase release of the major project.

Appendix C: Flowchart for Determining the Type of Business Case Summary Documentation Required



Notes:

(1) The term Project is to be interpreted as all types of investments, including those that are not categorized as projects; thus this flowchart applies also to such investments.

(2) Planned projects are projects listed on the BU/Corporate Function's project portfolio for the year in the current Business Plan (e.g., on the Approved New Starts List in Nuclear).

(3) Refer to the Risk Criteria listed in Table 1.

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ORGANIZATIONAL AUTHORITY REGISTER

Standard

TITLE

ORGANIZATIONAL AUTHORITY REGISTER

PURPOSE

The Ontario Power Generation (OPG) Organizational Authority Register (OAR) provides a framework of delegated authorities and position holders who can exercise those authorities. Authority is the right to order and make final decisions.

EXCEPTIONS

Subsidiary (SUB) Operations – The OPG OAR will be used to define approval limits for financial decisions made on behalf of a SUB, business venture with partners or related business alliance where an OPG employee is acting as a director/officer of said SUB regardless of the OPG employee's title or approval levels within that SUB unless specific approval authority is granted by the Chief Executive Officer (CEO).

AUTHORIZATION

SINGLE POINT OF CONTACT:	E. Louie Manager, Internal Control and Reporting Systems
GOVERNING DOCUMENT OWNER:	N. Reeve Vice-President, Financial Services

DOCUMENT RELATIONSHIP

Applicability:	OPG Wide
Receives Authority from:	OPG-POL-0024 Delegation and Exercise of Authority

DATES

Document Author Approval Date:	March 27, 2012
Review By:	March 27, 2014
Compliance Date:	March 30, 2012

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1.0 DIRECTION

1.1 Guiding Principles for the Exercise of Authority

1.1.1 Approval is based on the total known financial commitment, and must represent a proper bundling of work.

1.1.2 Authorities exercised are to be consistent with approved business plan and budget, unless specified otherwise.

1.1.3 The original initiator of a transaction cannot be the approver even if the transaction is within their assigned authority limits. Does not apply to energy transactions which have compensating controls.

1.1.4 Where elements exist for specific transactions, authorities for those items are by definition excluded from all other elements.

1.1.5 Authorities may be delegated on a temporary basis for a maximum of 3 months provided there is no conflict of interest. Authority delegations are effective on the date approved unless otherwise specified.

1.1.6 An incumbent occupying two positions may exercise the authority of both of those positions except where doing so would violate an established internal control.

1.1.7 The authority to requisition material, fuel, and contracted service in an emergency rests with station management at Band F and up. Both requisitioning and purchasing approvals must be obtained after the emergency has occurred.

1.2 Determination of Authority Level

Decision rules are to be applied in order.

Rule One: Authorities for Chief Executive Officer (CEO), Executive Leadership Team (ELT) Members, Senior Vice President (SVP) and Chief Nuclear Operating Officer (CNOO) are specifically listed by title/ELT membership.

Rule Two: Authority for Management employees is determined by Management Group Band D to H.

Rule Three: Other position holders are mapped as follows:

Level 2 Includes	• Society represented supervisors • Mgmt Band 17-I supervisors • Society Purchaser and Supervisory Purchaser (PWU) for Element 7.2 • Society represented Sales Specialist for Element 8.1 • Traders for Element 12 authorities
Level 1 Includes	• PWU represented supervisors • Mgmt Band 17-J supervisors • FLMa • Non-Supervisory PWU Purchaser for Element 7.2 • Developmental Traders for Element 12 authorities

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1.3 Authorities Delegated to All Position Holders

Element (i)	Transaction	Delegated Authority							
		CEO	ELT Member	SVP, CNOO	Management Band			Authority Level	
					D/E	F	G/H	2	1
1.1	**Projects and Investments – In Budget** Approve; Amend Scope; Amend Cost Estimate; Defer; Cancel (includes approval of cost transfer to current operations) Approvals are governed by OPG-STD-0076 Developing and Documenting Business Cases. Projects are defined and governed by OPG-PROC-0007 Project Accounting and Reporting	$40M	$20M	$10M	$5M	$2M	N/A	N/A	N/A
1.2	**Projects and Investments – Not in Budget** See Element 1.1 for inclusions and governance requirements.	$40M	$10M	$5M	$2.5M	$1M	N/A	N/A	N/A
1.3	**Business Development** Approve; Amend Scope; Amend Cost Estimate; Defer; Cancel (includes approval of cost transfer to current operations) Business Venture approvals are governed by FIN-PROC-PA-014 Managing Business Ventures with Partners.	$20M	$1M (SVP Corp Bus Dev only)	N/A	N/A	N/A	N/A	N/A	N/A
1.5	**Requisitions and Payment Requisitions** Approvals governed by OPG-PROC-0060 Requisitioning Items and Services and OPG-PROC-0051 Payment Processing. For Projects where a release strategy has been approved by the Board, authority for requisitioning may be delegated by the CEO.	>$40M	$40M	$20M	$10M	$5M	$2M	$50K	$10K
1.6	**Business Travel and Expense and Employee Relocation Interim Expenses** BT&E approvals governed by OPG-STD-0075 Business Travel and Expenses. External training >$10K requires pre-approval by an Executive Leadership Team member.	>$100K	$100K	$40K	$25K	$15K	$10K	$5K	N/A
1.7	**Declare Asset Surplus** Approvals governed by OPG-PROC-0081 Disposal of Surplus Assets; and one of: FIN-PROC-PA-005, Fixed Asset Accounting Procedure or OPG-PROC-0005 Materials and Supplies Inventory Accounting and Control	$10M	$7.5M	$5M	$2M	$500K	$250K	N/A	N/A

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Element (i)	Transaction	Delegated Authority							
		CEO	ELT Member	SVP, CNOO	Management Band			Authority Level	
					D/E	F	G/H	2	1
1.8	**Non-Charitable Research Funding and Collaboration Contracts/Agreements** Secondary approval by Law Division is required for information exchange agreements.	>$10M	$10M	$5M	$2M	$1M	N/A	N/A	N/A
1.9	**Local Sale of Surplus Assets** Approvals governed by OPG-PROC-0081 Disposal of Surplus Assets and OPG-PROC-0026 Billing and Recording of Accounts Receivable	>$25K	$25K	$10K	$5K	$1K	N/A	N/A	N/A
1.10	**Non-Energy Sales** Contracts/Agreements >$5M require stakeholder approval by Legal, Corporate Risk Management – Credit Risk, Controller and Taxation. Contracts up to $5M and outside the normal course of business for a business unit also require stakeholder approval by Legal, Site Controller and Taxation. Invoices are governed by OPG-PROC-0026 Billing and Recording of Accounts Receivables. Nuclear Commercial Services approvals are governed by N-PROG-AS-0009 Isotope Sales.	>$40M	$40M	$25M	$10M	$5M	$50K	N/A	N/A
1.11	**First Nation and Métis Capacity Development** For amounts >$100K with a recommendation by Director, First Nations and Métis Relations or for amounts <$100K secondary approval by Director, First Nations and Métis Relations. Approvals governed by OPG-PROG-0025 First Nations and Métis Relations Program	>$500K	$500K	$500K	$250K	$100K	N/A	N/A	N/A
7.3	**Low Dollar Purchases** Approvals governed by OPG-PROC-0051 Payment; OPG-PROC-0060 Requisitioning Items and Services; and OPG-PROC-0064 Purchasing Card.	All management and supervisory staff; and purchasing card holders Up to $10K per transaction							

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1.4 Authorities Restricted to Specific Organizations

Element (i)	Transaction	Delegated Authority							
		CEO	ELT Member	SVP, CNOO	Management Band			Authority Level	
					D/E	F	G/H	2	1
2.1	**Charitable and Not for Profit Donations** Restricted to Corporate Office.	>$25K	$25K	N/A	$10K	$10K	N/A	N/A	N/A
2.2	**Sponsorships for Brand building** Restricted to Corporate Office.	>$200K	$200K	N/A	$50K	$50K	N/A	N/A	N/A
2.3	**Requisitioning of Advertising** Advertising other than for vacancies or surplus asset sales. Restricted to Corporate Office.	>$6M	$6M	N/A	$2M	$1M	N/A	N/A	N/A
4.1	**Requisitioning of Legal Services** Approvals governed by LAW-PROC-0001 Acquiring Outside Legal Services. Restricted to Law Division.	>25M	$4M	N/A	N/A	$1M	N/A	N/A	N/A
5.2, 5.6, 5.8 Statutory and Mandated Payments see: OPG-PROC-0051Payment Processing for Vendor Invoices and Statutory Payments									
5.1	**Bulk Payroll Transactions** Restricted to People and Culture – Pay Services.	>$200M	>$200M	N/A	>$200M	$100M	$100M	N/A	N/A
5.1.1	**Individual Employee Payroll Transactions** Restricted to People and Culture – Pay Services.	>$3M	>$3M	N/A	>$3M	$3M	$3M	$300K	$300K
5.4	**Relocation Assistance Payments** Restricted to People and Culture Relocation Services.	>$1M	>$1M	N/A	>$1M	$400K	$200K	N/A	N/A
6.1	**Requisition Fuel**	SVP or higher unlimited within business plan							
6.2	**Purchase/Sale of Fuel; Water Rental Agreements** Approvals governed by N-PROC-MM-0040 Nuclear Fuel, EM-PROC-0022 Energy Markets Fuel Procurement and, for sales, OPG-STD-0072 Credit Risk Management Standard	>$200M	$200M	$200M	$50M	$25M	$15M	$5M	N/A

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Element (i)	Transaction	Delegated Authority							
		CEO	ELT Member	SVP, CNOO	Management Band			Authority Level	
					D/E	F	G/H	2	1
7.2	**Procurement Contracts** Approvals governed by OPG-PROC-0058 Procurement Activities or LAW-PROC-0001 Acquiring Outside Legal Services. Restricted to Supply Chain and Law (Legal Services). For Projects where a release strategy has been approved by the Board, the authority for procurement may be delegated by the CEO to the appropriate ELT member. *Contracts >$20M require secondary approval by the CFO *Contracts >$40M require secondary approval by the CEO	>$40M	>$40M*	>$40M*	$40M*	$15M	$3M	$1M	$500K
8.1	**Sale/Disposal of Assets** Approvals governed by OPG-PROC-0081 Disposal of Surplus Assets. Restricted to Investment Recovery.	$25M	$15M	$15M	$4M	$2M	$1M	$500K	
9.1	**Acquire, Manage, and Dispose of Real Estate Rights and Interests and Related Transactions** Approvals are governed by approved Real Estate procedures. Restricted to Real Estate.	>$10M	$10M	N/A	$5M	$1M	$500K	$250K	N/A
10	**Treasury authorities are documented in FIN-STD-0004 Treasury and Funds Management Organizational Authority Register.**								
11.1	**Customer/Vendor Refunds, Credits and Adjustments** Approvals governed by OPG-PROC-0026 Billing and Recording of Accounts Receivable and OPG-PROC-0051 Payment Processing. Restricted to Corp. Financial Processing, Energy Markets Controllership and Credit Risk.	>$2M	$2M	N/A	$1.5M	$1M	$500K	N/A	N/A
11.3	**Asset Adjustments** Approvals governed by FIN-PROC-PA-005, Fixed Asset Accounting and OPG-PROC-0005 Materials and Supplies Inventory Accounting and Control. Restricted to Finance.	>$10M	$10M	N/A	$5M	$2.5M	$1M	$0.5M	N/A
12.1	**Electricity Products, Derivatives and Services - Enabling Agreements** Includes confidentiality or similar agreements involving information on energy products and services. Excludes establishing specific product, price or quantity commitments. Approvals governed by OPG-PROG-0016 Credit and Market Risk Management Program and restricted to Corporate Affairs.	Unlimited				N/A	N/A	N/A	N/A

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Element (i)	Transaction	Delegated Authority							
		CEO	ELT Member	SVP, CNOO	Management Band			Authority Level	
					D/E	F	G/H	2	1
12.2	**Domestic and Interconnected Trading and Origination Activity; Options and Derivatives** – Restricted to Corporate Affairs								
12.2.1	Current Day (Real Time) Transactions previously approved under Element 12.2.3, do not require subsequent approval under Element 12.2.1 and 12.2.2.	>1,500 MW	>1,500 MW	N/A	1,000 MW	800 MW	800 MW	800 MW	N/A
12.2.2	Current Month (plus following when past mid-month)					700 MW	500 MW	300 MW	N/A
12.2.3	Hydro Quebec Segregated Transactions (Real and Current Month)					700 MW	550 MW	500MW	N/A
12.2.4	**Term from Deal Entry Date**	5 years >1,000 MW	5 years 1,000 MW	N/A	5 years 600 MW	5 years 500 MW	3 years 300 MW	2 years 100 MW	≤1-year 50 MW
12.3	**Ontario Hourly Bidding/Offering Activity** Restricted to individuals with a valid digital certificate and authorized by the Director, Portfolio Management. Applied to the quantity committed in each hour to the specific administered market and independently to the administered market and to the position with authority to engage in bids/offers in that market.	OPG Installed Capacity							As Assigned
12.4	**Domestic Sale of Independent Electricity System Operator Defined Ancillary Services** Restricted to Corporate Affairs.	> $48M	$48M	N/A	$12M	$6M	$3M	$1.5M	N/A
12.5	**Other Electricity Products, Derivatives and Services** Restricted to Corporate Affairs.	> $32M	$32M	N/A	$8M	$4M	$2M	$1M	N/A
12.5.1	**Physical Transmission and Financial Transmission Rights** Restricted to Corporate Affairs.	> $32M	$32M	N/A	$8M	$5M	$1M	$0.5M	N/A
14.1	**Aboriginal Settlement Agreements**	$5M	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1.5 Personnel Approvals

Apply to all Management and Supervisory Position Holders	• Timesheets and exceptions.	R1
	• Appointments, Terminations, Setting/Changing Rate Classification – for represented staff within Collective Agreement and HR governance parameters, non-represented staff within standard provisions • Leave of Absence	R2

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2.0 ROLES AND ACCOUNTABILITIES

2.1 Chief Executive Officer

Approves delegation of CEO authorities.

2.2 Position Holders

Comply with authority limits and specifications.

2.3 Site Controller/Local Finance Manager

Responsible for implementation of the OAR and providing advice to staff.

2.4 Manager, Internal Control and Reporting Systems

Responsible for managing the development, implementation and maintenance of the OAR.

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Rule of One (R1): Position holder approves items relating to a direct report

Rule of Two (R2): Position holder approves items relating to a direct report of a direct report

4.0 RECORDS AND REFERENCES

4.1 Records

Documentation of temporary delegations must be retained by the delegator.

4.2 References

4.2.1 Performance References

Governance required for specific approvals is referenced with the Element approval limits.

4.2.2 Development References

None

5.0 REVISION SUMMARY

This is an Intent revision. Changes are substantial and documented separately.

(i) Some elements have been removed. Remaining elements were not renumbered.

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Standard

TITLE
DEVELOPING AND DOCUMENTING BUSINESS CASES

PURPOSE
This Standard describes the minimum requirements for developing and gaining approval for investments and provides a description of required information to be included in a *Business Case Summary* (*BCS*).

EXCEPTIONS
None

AUTHORIZATION	
SINGLE POINT OF CONTACT:	S. Rogers Director, Asset Planning and Integration
GOVERNING DOCUMENT OWNER:	D. Power Vice-President, Investment Planning

DOCUMENT RELATIONSHIP	
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Standard

Title:
DEVELOPING AND DOCUMENTING BUSINESS CASES

1.0 DIRECTION

Business Case Summaries (*BCS*) shall be prepared in order to provide a concise summary of the business need, alternatives considered, economic evaluation, proposed solution, and the benefits and risks of a proposed investment. *BCS* approval releases a specific level of funding to achieve specific results in terms of scope, schedule, and cost, with an understanding of the associated risks. *BCSs* are also used as evidence of prudent decision making for regulatory purposes.

Business case development and documentation shall be scaled appropriately according to the nature and the level of investment. Three classes of investments and the corresponding three types of required documentation for a *BCS*, ranging from a simple form to a more detailed document, are defined depending on the nature, size, complexity, and risks of the proposed investment.

1.1 Overview

This Standard describes the minimum requirements for developing, documenting, and gaining approval of business cases for all investments. While the focus is on investments in projects, the Standard also applies to other business investment decisions, including mergers, joint ventures, acquisitions, and life cycle asset investment decisions such as major re-investments, refurbishments, and life extensions.

This Standard does not specify the activities to be carried out by the *Project Sponsor* and Project Executing Authority to ensure that appropriate front-end project development and stakeholder consultations are performed. These requirements are specified in Business Unit (BU) Project Management Governance. See Appendix A for a schematic of where this Standard fits in the context of related investment governance.

1.2 Needs Statement and Classification of Investments

Each business investment decision requires a needs statement. The need can arise in one of the following ways:

(a) **Sustaining Investments** to maintain facilities and equipment, to address potential or realized performance gaps (operational performance worse than target).

(b) **Regulatory Investments** to ensure compliance with new or changed regulations, thereby enabling continued operation of the facility.

(c) **Value Enhancing Investments** to reduce cost or increase revenue, or both, through improvements such as increased capacity, availability, or efficiency. Value Enhancing investments require a financial evaluation of the proposed alternative to demonstrate the added value.

(d) **Business Development Initiatives** to be explored or pursued, which include, but are not limited to:

- Asset development initiatives such as major plant rehabilitation, plant life extensions, new developments, redevelopments, and closures.

- Major acquisitions, mergers, divestitures, business ventures with partners; any significant departure from established strategies of the Corporation.

- Asset sales/swaps.

- New product development including participation in newer markets or products not previously approved.

1.3 Project Phases and Business Case Summaries

All Ontario Power Generation (OPG) projects progress through the phases of Identification, Initiation, Definition, Execution, and Close-Out utilizing the gated approach to project progression. During each of the Investment/Project Phases, Partial, Full, or Superseding *BCS* Releases may be utilized. Appendix B provides an overview of *BCS* documentation associated with different project phases and releases.

During the Identification Phase, to meet the requirements for Business Planning, Planning *BCSs* (to be documented on **OPG-FORM-0102, Planning Business Case Summary**) or equivalent document such as Asset Investment Screening Committee (AISC) Part A, are developed to list the project in the BUs Project Portfolios. If sufficient information is available during Business Planning, a Type 1 *BCS* (see Section 1.4.1) may be used in place of a Planning *BCS*.

Simple projects may require only one subsequent *BCS* to the Planning *BCS* in order to complete all of the Initiation, Definition, and Execution Phase work.

More complex projects may require a single *BCS* to complete the work up to the end of the Definition Phase, before seeking further *BCS* approvals to complete the work of the Execution Phase.

Very complex projects, in particular Business Development Initiatives, may require multiple releases within each of the Initiation, Definition, and Execution Phases of the project. This approach helps manage risk by applying lessons learned during each project phase, to improve project performance during subsequent phases.

All projects also require a *Post-Implementation Review* (*PIR*) **[R-4]** Plan.

Project cost estimates shall include appropriate contingency given the quality of the estimate. If known, the estimate class of the cost estimate shall be stated.

For capital additions, capitalization of expenditures normally begins at the Definition Phase of the project when the selected alternative has been determined and work is being done to progress that selected alternative (see Capitalization Eligibility Procedure **[R-6]**).

1.4 Scaled Documentation

BCS documentation and approval requirements are driven by the nature of work to be executed through the proposed investment/project, and the estimated cost of the investment/project.

If a project is emergent (i.e., not on BU Project Portfolio listing, no Planning *BCS*, or not on the current year's Approved New Starts List in Nuclear), it shall be documented using Type 3 documentation (see Section 1.4.3) to ensure proper documentation of the justification for the preferred alternative, which would have been provided through alternative documentation, such as a Life Cycle Plan (*LCP*), had the project been planned.

This Standard defines three levels of *BCS* documentation requirements:

(a) **Type 1 Documentation:** Applies to Sustaining and Regulatory investments/projects less than $10 M, which meet all other risk criteria for Type 1 Documentation, and which are not emergent.

(b) **Type 2 Documentation:** Applies to Sustaining and Regulatory investments/projects greater than or equal to $10 M but less than $25 M, and to all Value Enhancing investments/projects less than $25 M, which also meet all other criteria for Type 2 Documentation, and which are not emergent.

(c) **Type 3 Documentation:** Applies to all Business Development Initiatives, all emergent investments/projects, to Sustaining, Regulatory, and Value Enhancing investments/projects greater than or equal to $25 M, and to all other investments/projects that do not meet the criteria for Type 1 and Type 2 documentation.

See Table 1 below for a summary of criteria for the three types of documentation and their documentation requirements. See also Appendix C for a decision flowchart to determine which type of *BCS* documentation applies.

Table 1: Summary of Scaled Documentation Criteria and Documentation Requirements

<table>
<tr><th>Criteria</th><th>Type 1</th><th>Type 2</th><th>Type 3</th></tr>
<tr><td>Investment Class</td><td>Sustaining, Regulatory</td><td>Sustaining, Regulatory, Value Enhancing</td><td>Sustaining, Regulatory, Value Enhancing, Business Development Initiative</td></tr>
<tr><td>Emergent Project</td><td>Not Applicable</td><td>Not Applicable</td><td>Required</td></tr>
<tr><td>Total Estimated Cost</td><td>< $10 M</td><td>≥ $10 M but < $25 M</td><td>≥ $25 M</td></tr>
<tr><td colspan="4">Risk Criteria</td></tr>
<tr><td>Design Complexity</td><td>Minimal and simple; and uses technology that is proven or previously used.</td><td>Uses proven technology or methodology.</td><td rowspan="5">Does not meet Type 1 or Type 2 criteria.</td></tr>
<tr><td>Fabrication and Installation Risk</td><td>Requires simple processes.</td><td>Uses readily available processes and technology.</td></tr>
<tr><td>Safety Risks</td><td colspan="2">Not expected to introduce new safety (personnel, nuclear, or dam), fire, seismic, environmental, physical security or cyber/Information Technology (IT) security, or production risks.</td></tr>
<tr><td>Modification Risk</td><td colspan="2">Not an installation of a new station system, sub-system, or a significant change to existing systems.</td></tr>
<tr><td>Schedule Risk</td><td colspan="2">Sufficient float to ensure that any regulatory commitments and preparations for planned outage will be made on schedule.</td></tr>
</table>

Documentation Requirements	Type 1	Type 2	Type 3
Alternatives	Justification for preferred alternative already documented elsewhere, or no reasonable alternatives to the proposed solution.	Justification of chosen alternative required.	
Financial Evaluation	Not Required	Required for Value Enhancing investments/projects and updated for each release. Optional for Sustaining and Regulatory.	

1.4.1 Type 1 Documentation: Sustaining and Regulatory Investments < $10 M

Investments/projects that meet Type 1 criteria for documentation may utilize a single *BCS* to cover all of the Initiation, Definition, and Execution phase work, if practical. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

Since the alternatives for investments/projects that meet the Type 1 criteria have been already assessed in an *LCP* (or equivalent document), or if there are no reasonable alternatives available, there is typically no need to justify the chosen alternative in the *BCS* write-up. If justification is available (e.g., in an *LCP*), the *BCS* may refer to it.

Investments/projects that meet the Type 1 documentation criteria shall be documented on **OPG-FORM-0074, Type 1 Business Case Summary**. Guidance on the use of the form is included in the form.

1.4.2 Type 2 Documentation: Sustaining and Regulatory Investments ≥ $10 M but < $25 M, and all Value Enhancing Investments < $25 M

Investments/projects that meet Type 2 criteria for documentation may utilize a single *BCS* to cover all of the Initiation, Definition, and Execution phase work, if practical. Because of the complexity of these projects, it is likely that one or more *BCSs* will be required to progress the project to the end of the Definition Phase, and one or more *BCSs* may be required for the Execution Phase. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

If the only criterion which is requiring an investment/project to utilize Type 3 *BCS* documentation is the estimated total project cost, the investment/project may utilize Type 2 *BCS* documentation for the Initiation and Definition Phase releases, provided that the cumulative release amount (including committed spending) is less than $25 M. However, the Sponsor may still request Type 3 *BCS* documentation, if deemed more appropriate. Such a project shall utilize Type 3 *BCS* documentation for all releases which include Execution Phase work.

Investments/projects that meet the Type 2 documentation criteria shall be documented on **OPG-FORM-0075, Type 2 Business Case Summary**. Guidance on the use of the form is included in the form.

1.4.3 Type 3 Documentation: Investments ≥ $25 M, and all Business Development Initiatives

Investments/projects that meet Type 3 criteria for documentation are normally complex undertakings with long timelines and a significant degree of risk, and often require a phased approach to project development and approvals. Multiple releases of funds are often required for each Phase (Initiation Phase, Definition Phase, and Execution Phase). A comprehensive risk assessment must also be completed for each release, and documented in each *BCS*. This approach helps manage risk by applying lessons learned during each project phase, to improve investment/project performance during subsequent phases. The *Project Sponsor* should determine the release strategy in consultation with the Project Executing Authority.

Investments/projects that meet the Type 3 documentation criteria shall be documented on **OPG-FORM-0076, Type 3 Business Case Summary**, which consists of an Executive Summary and Recommendations section, followed by the main body of the *BCS* and Appendices. Guidance on the use of the form is included in the form.

1.5 Over-Variances and Superseding Releases

Investments/projects that require a cost or schedule over-variance approval, where there is no material change in scope, may utilize **OPG-FORM-0077, Project Over-Variance Approval**. Whether or not a scope change is considered material is left to the judgement of the Sponsor. The Project Over-Variance Approval form should not be used for over-variances in excess of 20% of cost or schedule or both.

Superseding Releases shall be used for investments/projects that encounter a material scope change, a significant change in the financial evaluation, or an over-variance in excess of 20% of cost or schedule or both. The type of *BCS* documentation of these superseding releases shall reflect the new costs and risk criteria.

For project deferrals, a memorandum, signed by the original *BCS* line approver, shall be used. This memorandum should document: (i) the rationale for the project deferral and its implications with respect to regulatory, health and safety, and economic targets in the original business case; (ii) when the project is expected to resume; (iii) any expected cost variance, annual cash flow impacts relative to the approved business case cash flows, and the expected accounting impacts; and (iv) alternatives to project deferral considered and the reasons why these were not selected.

2.0 ROLES AND ACCOUNTABILITIES

2.1 Approval and Review Accountabilities

For all *BCS* Types, project funding releases are to be approved in accordance with Elements 1.1 Projects and Investments – In Budget, 1.2 Projects and Investments – Not in Budget, or 1.3 Business Development Initiatives of the Organizational Authority Register (OAR) **[R-3]**.

All *BCS* Types require three signatures: (1) Recommended by; (2) Finance Approval; and (3) Line Approval (per OAR **[R-3]**).

2.1.1 Line Approval

For Initiation and Definition Phase *BCSs*, Line Approval authority applies to the cumulative total cost of work being committed, not the estimated total investment/project cost.

For *BCSs* that cover Execution Phase work, Line Approval authority applies to the estimated total investment/project cost (including contingency), plus any relevant incremental ongoing costs to which OPG is also committed as a result of the investment/project.

Table 2: BCS Signature Block

Recommended by	BU Head/ ELT Member	BU Head/ ELT Member	Project Sponsor	Project Sponsor	Project Sponsor	Project Sponsor
Finance Approval	← - - - - - - - - - - - - - - - See Finance Approval in Table 3 - - - - - - - - - - - - - - - →					
***Line Approval**	Board	CEO	ELT Member	SVP, DCNO	Band D/E	Band F

* If Line Approval authority's position matches more than one category, the highest ranked category will apply; e.g., an SVP who is also an ELT Member shall follow the "ELT Member" Line Approval OAR authority.

2.1.2 Finance Approval

Finance Approvals are shown in Table 3.

Table 3: Finance and Line Approvals for BCSs Corresponding to OAR

Line Approval	Board	CEO	ELT Member	SVP, DCNO	Band D/E	Band F
Finance Approval						
Nuclear	CFO	CFO	VP Investment Planning	*VP Nuclear Finance	*Director Controllership Nuclear Finance	*Director Controllership Nuclear Finance
Hydro/Thermal	CFO	CFO	VP Investment Planning	N/A	*Plant Group Station Controller	*Plant Group/ Station Controller
Corporate Functions (incl. Corporate Office, BAS, Finance, People and Culture, Law Division, and Commercial Operations and Environment)	CFO	CFO	VP Investment Planning	N/A	*Director Controllership Corporate Functions Controllership	*Finance Controller Corporate Functions Controllership

* For Initiation and Definition Phase *BCSs*, where the estimated total cost of the investment/project is expected to eventually require Finance Approval from the VP – Investment Planning or the CFO, the onus is on the Finance Approver to ensure concurrence from the VP – Investment Planning, prior to approving these *BCSs*.

2.1.3 Over-Variance Approval

Investment/project over-variances require approval by the original approval authority as per the OAR **[R-3]**. If the over-variance results in the total actual and committed cost to date (for *BCSs* up to and including Definition phase work) or the total project cost (for *BCSs* that cover Execution Phase) exceeding the approval limit for the original approval authority, higher approval authority is required to approve the over-variance.

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3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Business Case Summary (BCS): A summary document that provides sufficient information for decision-makers to evaluate, rank, and approve or reject an investment.

Emergent Project: An investment/project that is not on the BU Project Portfolio listing, has no Planning *BCS*, or is not on the current year's Approved New Starts List in Nuclear.

Life Cycle Plan (LCP): A facility LCP is an operation, maintenance, and investment plan that is intended to maximize the value of the facility. The LCP is consistent with corporate strategic direction, based on the facility Condition Assessment and a consideration of the alternatives and risks involved.

Post-Implementation Review (PIR): A systematic performance evaluation of a fully or partially completed project to assess the benefit realization of the project and to capture the lessons learned.

Project Sponsor: The individual responsible for:

(a) Developing and approving the project charter.
(b) Setting the project objectives and priorities.
(c) Obtaining funding approval.
(d) Monitoring project execution including resolving conflicts and problems.
(e) Managing related risks.

3.2 Abbreviations and Acronyms

AISC - Asset Investment Screening Committee
BAS - Business and Administrative Services
BCS - Business Case Summary
BP - Business Plan
BU - Business Unit
CEO - Chief Executive Officer
CFO - Chief Financial Officer
DCNO - Deputy Chief Nuclear Officer
ELT - Executive Leadership Team
IT - Information Technology
LCP - Life Cycle Plan
OAR - Organizational Authority Register
OPG - Ontario Power Generation
PIR - Post-Implementation Review
SVP - Senior Vice-President
VP - Vice-President

4.0 RECORDS AND REFERENCES

4.1 Records

The original approved BCS along with its supporting documentation is to be held by the Project Sponsor. Refer to the Records File Information on the BCS forms and the Project Over-Variance Approval form for record filing.

4.2 References

4.2.1 Performance References

- OPG-FORM-0074, Type 1 Business Case Summary.
- OPG-FORM-0075, Type 2 Business Case Summary.
- OPG-FORM-0076, Type 3 Business Case Summary.
- OPG-FORM-0077, Project Over-Variance Approval.
- OPG-FORM-0102, Planning Business Case Summary.
- OPG-PROC-0056, Post-Implementation Review.

4.2.2 Development References

[R-1] OPG-PROG-0006, Investment Management.
[R-2] OPG-PROC-0055, Life Cycle Plan Procedure.
[R-3] OPG-STD-0017, Organizational Authority Register.
[R-4] OPG-PROC-0056, Post-Implementation Review.
[R-5] OPG-STD-0062, Project Risk Management Standard.
[R-6] FIN-PROC-PA-003, Capitalization Eligibility Procedure.
[R-7] FIN-PROC-PA-014, Procedure for Managing Business Ventures with Partners.

5.0 REVISION SUMMARY

This is an Intent revision.

- Updated and streamlined overall document flow.
- Introduced new Planning BCS form OPG-FORM-0102 that was converted from the previous desktop template version.
- Provided additional clarity regarding the use of Type 1, Type 2 and Type 3 BCS documentation.
- Updated Finance Approval accountabilities.
- Clarified Over-Variance and Superseding Release criteria.

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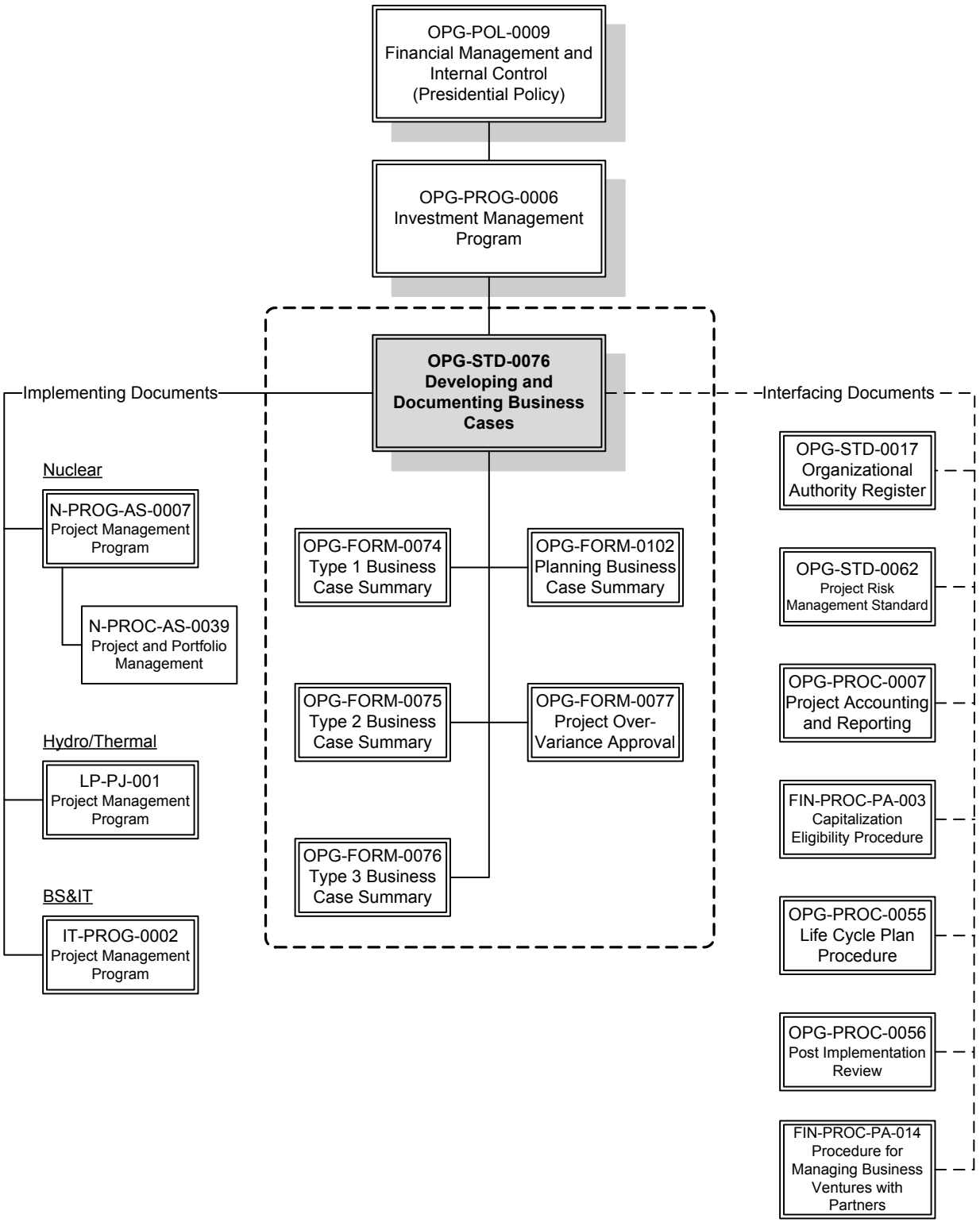
Appendix A: Document Relationships



Appendix B: Overview of Potential Business Case Summary Documentation at Different Project Phases

Business Case Summaries Which May Be Completed At Each Project Phase				
Project Phases per Project Development Protocol	**Identification**	**Initiation**	**Definition**	**Execution**
Description of Work	Identification and screening of a business concept or opportunity	Evaluation of a selected number of alternatives and selection of the preferred alternative	Development and definition of the preferred alternative	Delivery of the preferred alternative
BCS Required to Enter Project Phase	Planning *BCS* or AISC Part A	**Initiation Phase BCS**	**Definition Phase BCS**	**Execution Phase BCS**
Partial Release		**Used only if Phase needs to be performed in stages.** (Multiple partial releases are allowable)		**Used only if Execution Phase work needs to be performed in stages** (e.g., to sign execution contracts for execution on initial phase/unit in a multi-phase/multi-unit project)
Full Release		Full release for **Initiation Phase Work**	Full release for **Definition Phase Work** (Simpler projects may use a Full Release Definition Phase *BCS* for all of the Initiation and Definition Phase work)	Full release for **Execution Phase Work** (Very simple projects may use a Full Release Execution Phase *BCS* for all of the Initiation, Definition and Execution Phase work)
Superseding Release		**Used on an exception basis only** Re-issued *BCS* with analysis justifying suspension, cancellation, or continuation of work **for the applicable Phase** following a material scope change, material schedule change, or material cost overrun(1)		
Approval Authority Level for Funding Releases (OAR)	Funding identified in Sponsoring BU's Approved BP/Budget	Based on **cumulative cost of work being committed** (i.e., including cancellation and demobilization costs); subject to limits in OAR *(Note: OAR approval level should be set based on total estimated project value, if work being committed in these phases effectively commits OPG to the total project)*		OAR Approval based on **estimated total cost of project**
Typical Funding Source for Capital Projects	OM&A	OM&A(2)	Capital	Capital

(1) In case of cost overruns less than or equal to 20%, the Project Over-Variance Approval Form OPG-FORM-0077 shall be used, rather than a Superseding *BCS*. An updated financial analysis shall be provided for Value Enhancing projects. Refer to Section 1.5, Over-Variances and Superseding Releases for details.

(2) Where a major project already has an approved Definition Phase release (and hence is being capitalized), expenditures on Initiation Phase work of sub-projects of that major project can also be capitalized, as these expenditures are funded under the Definition Phase release of the major project.

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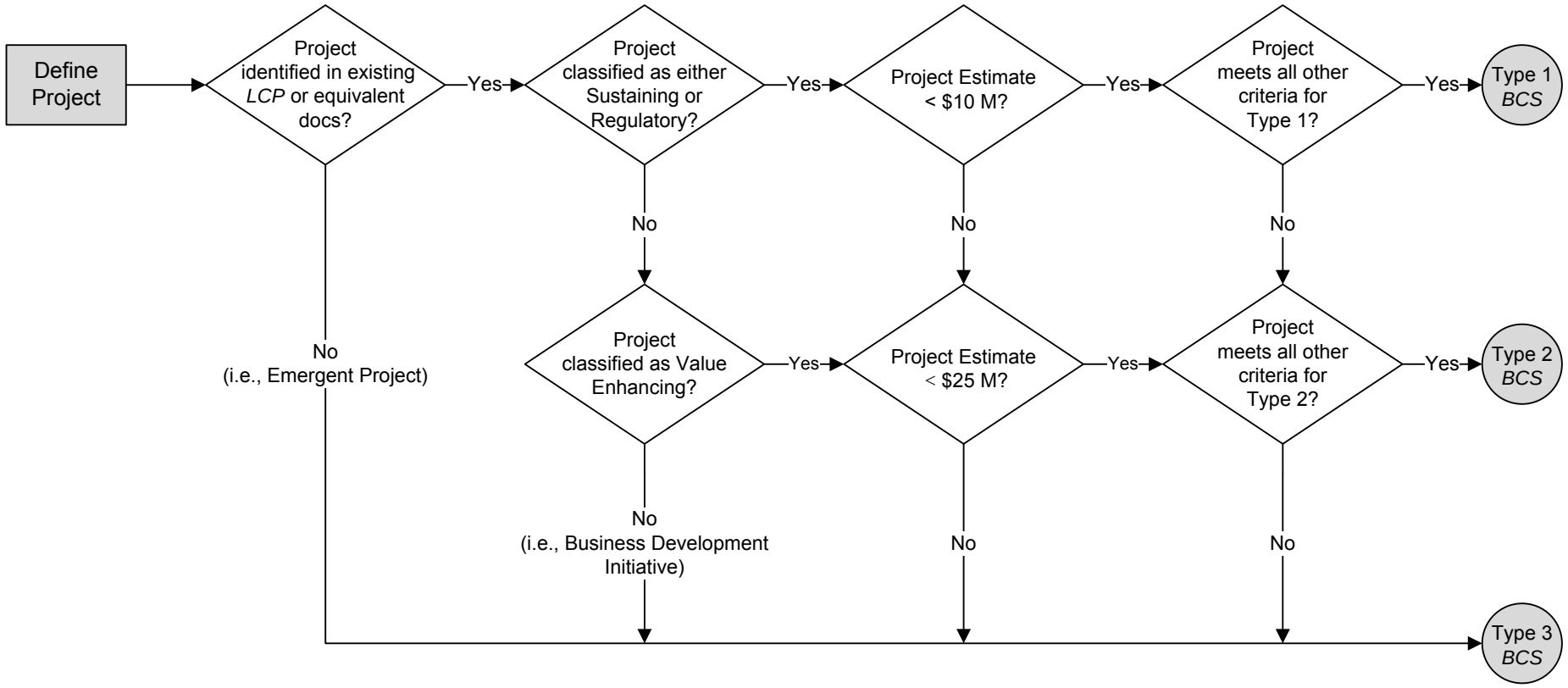
Appendix C: Flowchart for Determining the Type of Business Case Summary Documentation Required



Notes:

(1) The term Project is to be interpreted as all types of investments, including those that are not categorized as projects; thus this flowchart applies also to such investments.

(2) *LCP* or equivalent docs are documents such as the BU Project Portfolio listing, a Planning *BCS*, or the current year's Approved New Starts List in Nuclear.

UNDERTAKING J15.3

Undertaking

To provide the mandate or terms of reference for the Centre of Excellence group, if available.

Response

OPG established the Project Excellence Initiative in recognition of OPG's plan to invest significantly in the next ten years and into the foreseeable future in projects to sustain plant operations and as a primary vehicle for company growth. As part of this initiative, the Project Management Centre of Excellence (PM CoE) will be established with the goal of improving project outcomes across OPG. The PM CoE will leverage experience from the Darlington Refurbishment Program's Facilities and Infrastructure projects and Safety Improvement Opportunities, including implementing the lessons learned and corrective actions from the execution of the projects cited on pages 18-21 of the Second Quarter 2014 Supplemental Report to the Nuclear Oversight Committee by Modus/Burns & McDonnell (see Attachment 1).

A summary of the Project Excellence Initiative is attached as Attachment 2. In particular, the Terms of Reference for the PM CoE are found at page 4 of Attachment 2. As noted in the Terms of Reference, the primary objective is to develop and recommend to the Project Excellence Steering Committee strategies for establishing:

- A **common, scalable project delivery model** for all projects across all business units that focus on delivering projects safely, at the required quality, on time, and on budget, with all project goals met.
- A **Project Management Centre of Excellence** organization model where project management expertise, best practices, tools, processes and lessons learned are available to all OPG projects.

The Project Excellence Initiative, including in particular the PM CoE, formalizes the process by which the Projects and Modifications organization will adopt the key lessons learned observed by Modus/Burns & McDonnell in Attachment 1. For example, the Project Excellence Initiative specifically identifies the importance of the Gate Review Board and the Asset Investment Steering Committee, and the need to establish project management processes that support it (Attachment 1, pp. 19-20 and Attachment 2, p. 3).

As of March 2017, Nuclear Operations has officially launched the PM CoE, with a target to have the PM CoE fully operational by July 1, 2017.

Supplemental Report to

Nuclear Oversight Committee

2nd Quarter 2014

Darlington Nuclear Refurbishment Project

Burns & McDonnell
Modus Strategic Solutions

June 26, 2014

CONFIDENTIAL

I. Executive Summary

Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") provide the following Supplemental Report to the Nuclear Oversight Committee of the OPG Board of Directors ("NOC") regarding the status of the Darlington Nuclear Generating Station's Refurbishment Project ("Project" or "Refurbishment Project"). BMcD/Modus was requested by NOC to provide a Supplemental Report that summarizes our role, the oversight activities we are performing on the Project and major findings to date, while at the same time providing the broader context for these findings in light of the influx of new members to OPG's Board of Directors ("BOD") and NOC. In this regard, it is important that the comments and recommendations that BMcD/Modus made with respect to the Campus Plan Projects in our 2Q 2014 Report dated May 13, 2014 are viewed with the proper perspective. Additionally, BMcD/Modus provides NOC with an update on the issues raised in our reports to date and the Darlington Refurbishment Team's ("DR Team") responses and resultant actions to those issues.

In this Supplemental Report, we provide the following:

- Background of the Refurbishment Project including the pre-requisite Campus Plan Projects;
- Summary of BMcD/Modus's Oversight activities to date;
- Industry perspectives on critical issues that impact megaprojects like the Refurbishment Project;
- Summary of our NOC reports to date, highlighting our recommendations and the actions that OPG management has taken in response.

BMcD/Modus's engagement as the External Oversight team for the Project began on February 25, 2013. Since that time, we have provided NOC and the DR Team four reports, starting with an Initial Project Assessment report on August 13, 2013 that reviewed the DR Project's progression to the Release Quality Estimate ("RQE") in support of the Project. OPG has committed to providing the Shareholder with the RQE in October 2015. Subsequently, we provided three quarterly reports to NOC, each of which provided an assessment of the Project's current risks as well as more detailed "deep dives" into specific areas of interest. Our prior reports are attached as Exhibits 1-4.

As will be discussed in detail herein, BMcD/Modus has drawn the following major conclusions regarding the Project's current overall health:

- The Refurbishment Project is advancing at an appropriate pace toward the RQE milestone. The majority of the contracts for the Definition Phase have been awarded and essential preparatory work is moving forward. The upcoming 4d Cost Estimate will provide the DR Team with an essential "dress rehearsal" for RQE that will highlight gaps and challenges; these will require the Team's intense focus over the following year.
- The heart of the Refurbishment Project is the Retube & Feeder Replacement ("RFR") work which makes this the most significant risk. Prior CANDU refurbishments have suffered significant delays, cost overruns or both in this aspect of the work. The DR Team has incorporated in its planning the lessons learned from these prior refurbishments and other power megaprojects in order to mitigate the known risks. These mitigation activities include starting planning four years in advance of execution, completion of detailed engineering prior to the start of construction, and building a full scale mock-up to mitigate or avoid the issues that have adversely impacted prior refurbishments.
- The DR Team has devoted significant effort to locking down the Refurbishment Project's scope for RFR and other regulatory and non-regulatory life extension work, and is endeavoring to complete all detailed engineering by May 2015 in order to produce a high quality Project cost estimate for RQE. Engineering is currently challenged to meet this milestone. While it is implementing a plan to streamline its work, this will require intense monitoring and focus. The DR Team's approach toward scope management is a direct course correction from prior refurbishments including Pickering A Unit 4, and provides evidence that the team is inserting lessons learned into its plan.

- The DR Team has shown the willingness to change and evolve as issues have arisen. The DR Team determined that such key areas as scope development, schedule methodology, project reporting and the BOP procurement method required changes, and the DR Team has made those changes. Further management challenges will present themselves as OPG recognizes that a multi-year megaproject is a different endeavor than the company's day-to-day business practices. In our 2Q 2014 Report, we identified corporate procurement and hiring processes as areas for OPG to examine, as corporate policies and controls needed for the Project may vary from those used for OPG's core business.
- Project & Modifications' ("P&M") early management of the pre-requisite Campus Plan Projects, and in particular the D2O Storage Facility and Auxiliary Heating Steam system ("AHS"), exposed some critical project management gaps. The initial cost estimates for these two pre-requisite projects were poorly developed, thus the cost variances now reported are being compared to poorly developed baseline budgets. Senior management addressed these problems by making changes at the Project executive level, installing new leadership with proven ability, and altering the management model. While these pre-requisite projects will cost more than initially anticipated, and continue to present schedule threats to Refurbishment, P&M's new leadership has this work and other Campus Plan Projects on a much more predictable course. Moreover, many of the cost variances appear to be scope based, i.e. OPG is getting more value albeit for a higher cost.
- The causes of the cost overruns in the early Campus Plan Projects root from mistakes made by management that are not being repeated on the Refurbishment Project. There is no evidence we have seen to date that the problems we found in management of the D2O Storage and AHS projects represent a trend or a systemic failure for the Refurbishment Project.
- Both P&M and the DR Team have learned early and essential lessons from D2O Storage and AHS and are using these lessons to modify OPG's management plan for the entire Refurbishment Project. In particular, P&M is abandoning the "hands-off" contractor oversight strategy that was initially prevalent and is adopting an active management role, while the DR Team used these lessons to increase contractor accountability. It is important to note, however, that this is a cultural shift that will present on-going challenges to the organization in the short term.

At this time, the most significant question is whether the upper-end of the Refurbishment Project's anticipated $6-$10B[1] cost is at risk. In all, OPG believes that the cost variances from the Campus Plan Projects will be approximately $290-325M which equates to approximately 2.5-3% of the Refurbishment Project's total $10B working budget. Even if the Campus Plan Projects' overruns are 50% higher than current projections, the Refurbishment Project would still have preserved over $2B in contingency and management reserve remaining as part of its working budget. Since the Project is still in the Definition Phase, the cost estimates for the work, contingency and related scope decisions will remain under review until RQE.

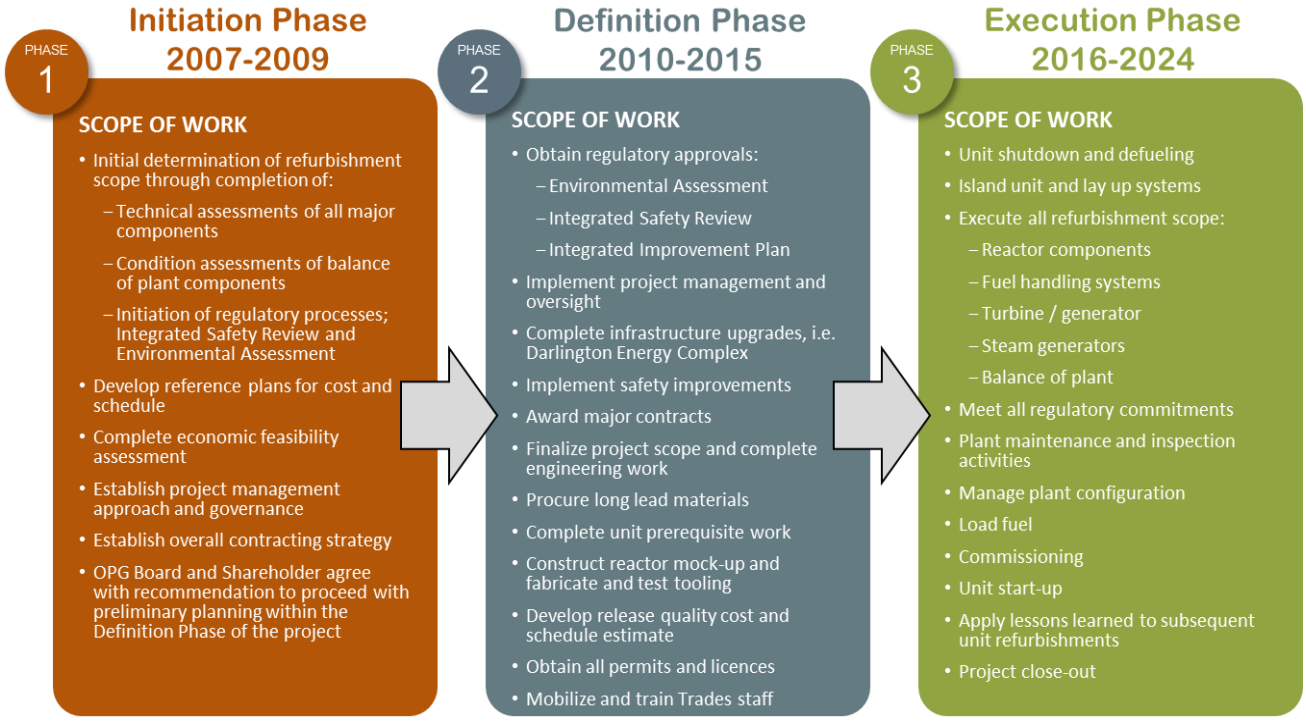
II. Background

A. The Project

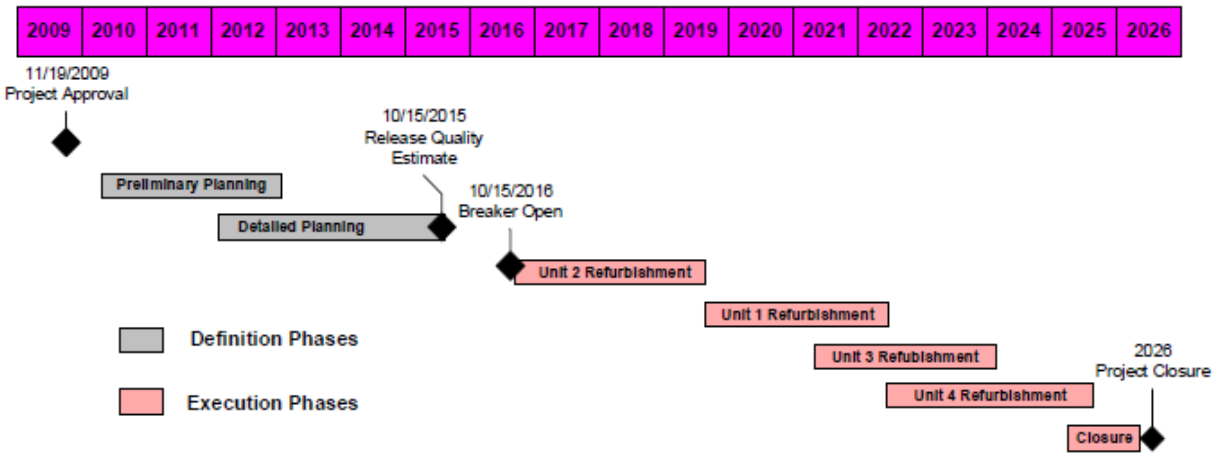
Due to the longevity of materials operating in high radiation fields, the Darlington Nuclear units are currently predicted to reach their nominal end of service lives in 2019 to 2020. However, various factors from Darlington operations could result in the units reaching the end of life earlier or later than the present predictions indicate. In June 2006, the Ontario Government directed OPG to begin feasibility studies regarding the refurbishment of the Darlington Nuclear plants in order to extend their service lives. In late 2007, OPG commenced "Phase I" of the Project called the "Initiation Phase" in order to determine the preliminary scope of work for the Darlington Refurbishment Project and to perform an

[1] This initial cost range for the Project was prepared and presented in 2009, and therefore is expressed in CAD $2009. Due to the length of the Project, escalation from market forces, cost of living increases, and other time-valued costs could not be calculated with confidence, and therefore is not included in the estimated cost.

economic feasibility assessment. Phase I was completed in 2009. The following graphic from the Refurbishment Team provides an overview of the Refurbishment Project's three phases:



The Refurbishment Project is currently in the Definition Phase, during which the DR Team anticipates completing award and negotiation of all vendor contracts, finishing detailed design, performing the front-end planning and locking down the Refurbishment Project's scope, budget and schedule. In addition, the Campus Plan Project work is to be largely completed in this period (with some work extending beyond RQE), as each of these various projects is needed in some manner before the breaker open of Unit 2. The phasing of the work depicted above allowed for the Project to proceed with its initial planning based on yearly incremental funding releases approved by the BOD with developmental targets and key milestones optimized for the completion of the RQE in October 2015. RQE will be the definitive estimate for the Execution Phase of the Project. Breaker Open for Refurbishment of Unit 2 (the first unit to be refurbished) is scheduled for October 2016 as depicted in the schedule below:



From the above schedule, it is worth noting OPG's major decision to "unlap" the execution of the first and second units. The Project's initial schedule required that the refurbishment of the second unit would begin before the first unit was returned to service. In the summer of 2013, Refurbishment Project management presented the current sequence that allows for the full "breaker-to-breaker" performance of Unit 2 prior to the start of the subsequent units. Management based this decision on the need for the first unit to be the singular focus of the DR Team during this time period and to allow adequate time to incorporate any lessons learned or process improvements into the next units' work. BMcD/Modus supported this decision, which was approved by the BOD as part of the 2014 Business Plan.

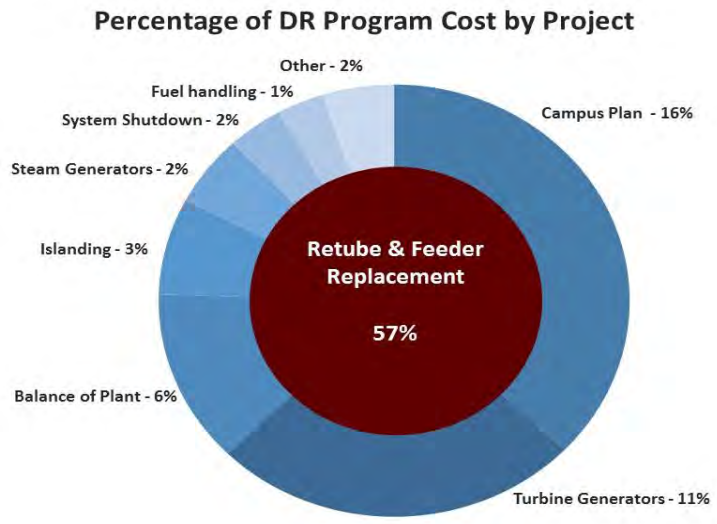
B. Project Management Model

OPG has chosen to manage the Darlington Refurbishment as a "Program." According to the Project Management Institute ("PMI"), "A Program is a group of related projects managed in a coordinated manner to obtain benefits and control not available from managing them individually." OPG's stated overall commercial strategy for the Program is premised on OPG acting as the General Contractor and Program Manager for the full Program. Within the Program, there are seven discrete Projects, each with its own project management team (including functions that are matrixed, such as engineers, commercial managers and project controls leads). The seven Projects (also known as "Project Bundles") encompass the following scopes of work:

- Retube and Feeder Replacement
- Islanding/Containment Isolation
- Fuel Handling/Defuelling
- Turbine Generator Maintenance and Controls Upgrade
- Boiler and Auxiliary Systems (Steam Generator Lancing)
- Shutdown, Layup and Services
- Balance of Plant

Each of these Project Bundles is being procured on an Engineer, Procure and Construct ("EPC") basis, meaning that a single contractor will be responsible for providing the all three services under a single contract. In addition to the Refurbishment Project, there is a significant amount of work (including the Campus Plan and other prerequisite projects) that needs to be completed and placed in service prior to the Execution Phase in order to support Refurbishment. The DR Team is responsible for planning and executing the bulk of the Refurbishment Project work. The P&M organization is responsible for completing the Campus Plan and other prerequisite projects. In contrast to the Program approach adopted by the DR Team, P&M is responsible for managing a Portfolio of hundreds of small projects for the Darlington and Pickering nuclear generating stations and the Western Waste Management facility.

In discussing specific aspects of the Campus Plan or the Project Bundles, it is possible to lose sight of the fact that the Retube and Feeder Replacement ("RFR") Project comprises the majority of the Refurbishment—in terms of schedule, budget and complexity, and as a result, comprises the most risk. As an example, for this Project, the major objective is the retubing and feeder replacement of Darlington's four nuclear units so that the plant can operate for another 30 years. All of the Refurbishment Project's other goals are subsidiary to the RFR work. Sixty percent (60%) of the Project's critical path is formed from the RFR scope; the remaining critical path work is either in preparation for RFR or commissioning and re-starting each unit after RFR completes. The following diagram depicts how much larger the RFR project is in comparison to all other project work, including the Campus Plan Projects:



Source: 4c Cost Estimate excluding contingency and functional costs, 2013; updates were made by BMcD/Modus to the RFR and Campus Plan Projects to reflect the most likely current estimates.

C. The Process for Developing RQE

Large, complex projects in general, and nuclear refurbishment projects in particular, have been challenged to meet their original budgets and schedule. For purposes of measuring the maturity of a project, the industry commonly uses project scope definition as a leading indicator of the underlying quality of a project's cost estimate and schedule. Projects can be at risk if they start construction prior to completing engineering, though this is a fairly common practice in the industry. For purposes of tethering its estimating effort to known industry standards, the DR Team has embraced utilizing the estimating standards from the Association for the Advancement of Cost Engineering ("AACE") and its guidelines for the classification of cost estimates[2]. These guidelines establish engineering and scope definition as the key underlying metric for developing certain "classes" of cost estimates from Class 5 (most conceptual with the largest range of potential variability) to Class 1 (most mature with the narrowest range of potential variability), as follows.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[2] AACE's Recommended Practice No. 17R-97, Cost Estimate Classification System (November 29, 2011) and Recommended Practice No. 18R-97 Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries (November 29, 2011).

Thus, RQE for Refurbishment is intended to be a Class 2 Estimate, a type of estimate that typically forms a project's "Control Budget." By utilizing this methodical approach to developing RQE, the DR Team should be able to produce a high-confidence estimate against which the Project's performance can be properly measured so long as each of the inputs are carefully vetted and understood. It is also important to understand and accurately characterize what each of the estimates represent prior to RQE within the context of the level of project definition and the accuracy range. It is not unusual on highly visible projects for actual project costs to be compared against early (i.e. Class 5) point estimates without a discussion of their accuracy ranges, which could mislead external stakeholders.

A concept within the estimate that is commonly misunderstood is the application of contingency. Contingency is included in the base estimate and refers to costs that will probably occur based on past experience. As a result, contingency is expected to be spent as the project progresses through its life cycle. The utilization of contingency is not an indication of poor management.

OPG is taking significant steps in engineering and scope definition in order to provide a fundamental basis for RQE by: 1) utilizing the AACE guidelines to characterize the Project's scope and engineering maturity through a progression of cost estimates; 2) completing detailed engineering prior to the start of construction for all work; and 3) mitigating potential performance risk and estimating errors through construction and the use of a full scale mock-up for RFR. Proper planning of the execution phase of the Project will provide confidence in the reliability of RQE as well as minimize the risks of cost and schedule overruns during construction.

D. Timeline of Key Events

The following timeline of key events shows the parallel development of the Campus Plan Projects and the Refurbishment Project.

Date	Key Events
	Early Project Development – Initiation Phase (2006 to 2010)
2006 – 2010	• Feasibility studies for DNGS Refurbishment, leading to February 2010 announcement of Refurbishment Project • DR Program Charter approved • D2O Storage and Auxiliary Heat Steam system projects approved, then put on hold • Refurbishment Project's Scope Definition Phase begins, categorizing core and non-core scope • Environmental Assessment Studies submitted to the CNSC • Procurement process for RFR project begins
	Refurbishment Project Definition Phase (2011 to Current)
2011	• Bill Robinson retires; replaced by Albert Sweetnam as SVP of Nuclear Projects • Mike Peckham named VP of Projects & Modifications • OPG submits Integrated Safety Review (ISR) to CNSC • Environmental Impact Statement issued • Project charter for D2O Storage project issued August 2011; high-level scope and estimate of $210M provided to P&M management • Refurbishment Project' Release 4a Cost Estimate provided to Board of Directors
1Q 2012	• P&M negotiates and executes Extended Service - Master Service Agreements ("ESMSA") with two vendors – Black & McDonald and ES Fox – for use on Campus Plan Projects • SNC/Aecon Joint Venture selected as EPC for RFR project
2Q 2012	• D2O Storage Gate 3A conducted with revised EPC Project estimate - $108M • DR scope review conducted to identify potential scope to be deferred
3Q 2012	• AHS bid and award of EPC to ES Fox – total project estimate - $45.6M
4Q 2012	• P&M seeks full funding releases for D2O Storage and AHS • Refurbishment Project Release 4b cost estimate shows potential for upward pressure on budget

Date	Key Events
1Q 2013	• Refurbishment begins early gate review process for major projects • P&M publishes Lessons Learned report for D2O Storage – schedule overruns and multiple rejections of vendor's conceptual design lead P&M and Refurbishment to change model of development of project scope • Change in engineering strategy presented to NOC • Mr. Sweetnam leaves OPG • BMcD/Modus begins role as Independent External Oversight to NOC
2Q 2013	• Mr. Robinson returns as SVP of Nuclear Projects • DR Team management identifies early lessons learned from EPC model and moves to more direct oversight of contractors • Refurbishment scope review identifies priority ranking of project work • Refurbishment presents strategy to streamline Project by "unlapping" Unit 2, rationalizing project scope and deferring Turbine Generator controls to next unit • SNC/Aecon provides Class 4 project estimate for RFR project
3Q 2013	• Mr. Peckham leaves OPG • BMcD/Modus provides Initial Project Assessment to NOC • Refurbishment scope review performed based upon operational experience • Refurbishment revises procurement approach for Balance of Plant ("BOP") allowing direct award of work based on vendor qualifications • Soil conditions and underground utilities delay and increase cost of Campus Plan Projects within DNGS protected area • Refurbishment modifies scheduling approach for Definition and Execution Phases, embracing a level 3 integrated, resource loaded schedule
4Q 2013	• Integrated Implementation Plan (IIP) and Global Assessment report (GAR) submitted to CNSC • Release 4c Cost Estimate provided to BOD – overall cost estimate of $10B (with $2.1B contingency and $800M management reserve) with reductions in scope and unlapping • Results of the scope review by the Blue Ribbon panel reduces the Refurbishment Project's cost and defer execution of non-Refurbishment enhancements • Contractors release estimates showing variances to original contract values for D2O Storage and AHS after BOD approval of the 4c Cost Estimate.
1Q 2014	• Minister's Long Term Energy Plan released • Terry Murphy begins as VP of P&M • Refurbishment and P&M begin collaborative approach to engineering, scoping, planning and cost estimating of Campus Plan Projects and BOP work • Turbine Generator performance contract awarded to SNC/Aecon • P&M team provides root cause analysis of delays to D2O Storage; Mr. Robinson requests BMcD/Modus to provide independent assessment • Revised cost estimates for Campus Plan Projects provided by ESMSA contractors, leading to revisions to Business Cases • RFR mock-up facility completed
2Q 2014	• Revised BCSs presented to BOD for approval for Campus Plan Projects – AHS, Water & Sewer and OSB – management defers request for funds for D2O Storage, awaiting updated Class 2 estimate from vendor • BMcD/Modus provides assessment of Campus Plan Projects to NOC • SNC/Aecon produces Class 3 RFR Estimate for OPG's vetting

III. BMcD/Modus' External Oversight Role

After a thorough RFP and selection process that started in April of 2012, OPG contracted with BMcD/Modus to provide External Oversight services for the Refurbishment Project. This engagement began on February 25, 2013. BMcD/Modus assigned very senior level individuals with extensive experience and expertise in all aspects of nuclear project development, management and independent oversight. Our central role is to report to NOC and assist the SVP Nuclear Projects by providing independent assessments on the performance of the Refurbishment Project. At a high level, this involves:

- Reviewing and monitoring the definition, development and risk management of the Refurbishment Project;
- Monitoring progress of the Refurbishment Project against targets, including cost, schedule and risk;
- Reviewing execution performance of the Refurbishment Project; and
- Offering recommendations for improvement where appropriate.

The BOD approved our Work Plan for performing oversight activities on the Project in May 2013 and included both day-to-day monitoring of events and "deep dives" on critical areas that we believed would be indicative of the Refurbishment Project's health. We anticipated developing reports for NOC that would track the status of the Refurbishment Project's activities in an ongoing manner and provide our view of the Project's risks and potential gaps, as well as recommendations for mitigating those risks. Our focus during the Definition Phase has been to examine the DR Team's planning efforts related to the Project's development of scope, schedule, cost and risk identification which are the key inputs to RQE. To date, the cooperation from OPG and Refurbishment contractors has been excellent. The BMcD/Modus team has had the appropriate level of access to personnel, documents and meetings, which provides insight and clarity to Project activities and plans.

IV. Industry Perspective

In our engagement, we are relying on our team members' long history with large capital megaprojects, particularly in the nuclear industry. Megaprojects (generally defined as high-profile projects costing more than $1B) have a rhythm all their own and typically involve large sums of money, lengthy, multi-year project schedules and significant risks to the companies who engage in them. In 2013, the Project Management Institute ("PMI") produced a study for its Global Executive Council membership which demonstrated the high cost of poor performance on megaprojects. PMI's study found that 28% of project funding is at risk in organizations that do not properly plan and manage capital projects.[3] This figure is in comparison to 2% of the budget being at risk for high-performing organizations.

Gaining understanding of these common megaprojects' risks requires understanding of certain essential facts:

- Megaprojects like the Refurbishment Project need large, clearly visible objectives so that all participants and stakeholders can objectively measure progress towards these major goals. RQE is an example of such a major goal.
- Major project goals (cost, schedule, performance) need to be viewed as a whole, rather than as a sum of the parts. As such, megaprojects' risks need to be viewed at a macro level, as day-to-day assessments can be misleading and uninformative. As an example, an owner could chose to mitigate a larger risk to the overall project by accelerating a predecessor project at additional cost. Without the context of the larger project, the cost-benefit analysis to incur the additional cost could not be justified.

[3] Project Management Institute "2013 Pulse of the Profession™: The High Cost of Low Performance," October 2013.

- Engineering and scope identification are the most common leading indicators of a megaproject's success. Projects with loose scope or engineering errors, omissions and schedule delays are typically beset with large cost increases and additional downstream schedule delays. A common mistake that usually results in such increases is beginning work in the field without a completed design and appropriately sequenced work. This was a key factor in the cost overruns for Pickering A Unit 4 which OPG first addressed with Pickering A Unit 1 and now with the Refurbishment Project.
- Owners typically rely on large, sophisticated contractors with requisite experience for megaproject performance, and the contracting model owners typically default to is EPC. However, even when EPC contracts are on a firm, fixed-price (which the EPC contracts for the Refurbishment Project are not), the contractors never accept as terms of the contract all of the performance risk, as the premium a contractor would demand to shift such a large amount of risk would be untenable. Therefore, owners must decide their level of risk tolerance and negotiate for appropriate levels of transparency and control over the performance of the work. With the exception of the ESMSA, the EPC contracts for the Project were all negotiated with the specific scope of work for each Project Bundle in mind.
- Non-critical work on megaprojects needs to be properly calibrated to either facilitate or stay out of the way of the work that is on the critical path. Nuclear operations tends to insert processes, appropriate for the discipline and certainty required for an operating nuclear generating station however, in a project environment these same processes make work management exceptionally complex. A key part of our Independent Oversight role is identifying issues that could draw away the attention of management from the most critical work.

Our experience with megaprojects similar to the Refurbishment Project—including, for many on our team, the Return to Service of Pickering A Unit 1 a decade ago—allows BMcD/Modus to characterize the effort required and expended on this Project. There are three core nuclear industry principles that are essential ingredients to our oversight mission:

(1) In the nuclear community, there is wide acceptance of the need for ***continuous improvement*** based on learning lessons from operational experience ("OPEX"), which provide a basis for judging progress and effectiveness;

(2) Nuclear projects and operations are in a constant search for corrective actions which are specific recommendations for mitigating or recovering from problems; and

(3) When problems are identified and corrective actions attempted, it is essential to establish the extent of the condition to properly characterize the magnitude of any one problem or set of problems.

These concepts must work in unison; otherwise one can get an entirely false read of the significance of issues as they arise. As an example, during operations of a power plant, each "Station Condition Report" or "SCR" documents and reports events of all types with the same level of veracity. However, SCRs can range in significance from serious problems like a unit trip to a line worker slipping on the ice during winter. Thus, defining the extent of condition provides management with the appropriate characterization of a potential problem.

Our reports incorporate these principles so that management and the NOC can understand the nature of a deficiency, see the recommended solution or corrective action that management is taking, and evaluate the extent to which this problem impacts the overall Project. In preparing our reports, BMcD/Modus intentionally seeks out areas where there are perceived gaps and we attempt to define and characterize the risks these problems may present to the overall Project.

V. Synopsis of BMcD/Modus Reports and Major Findings

As part of our NOC approved Work Plan, in August 2013, BMcD/Modus produced an Initial Project Assessment Report ("Initial Assessment Report") in which we established a baseline for assessing and measuring the DR Team's activities through the current Definition Phase. Subsequently, BMcD/Modus has produced three quarterly reports to NOC.

BMcD/Modus prepares these reports for NOC as a continuous progression of the Project's status in which we identify areas for the DR Team to focus and monitor their efforts to recover or fill gaps. Throughout, we have identified both gaps for the DR Team to address and positive developments from which the NOC should draw a measure of confidence that the team is working toward the Project's ultimate goals. The following summarizes the topic areas and major findings from each of our reports to date.

BMcD/Modus Reports to NOC as of 2Q 2014	
Report Summary	**Major Findings**

Initial Assessment Report – August 13, 2013
• Finalized BMcD/Modus Work Plan
• Benchmarked the Status of Key Planning Activities
• Benchmarked the Status of Major Project Bundles
  ○ Retube and Feeder Replacement (RFR)
  ○ Balance of Plant (BOP)
  ○ Campus Plan
  ○ Turbine Generator
  ○ OPG Critical Path Activities
	The Refurbishment Project is appropriately advancing at the time of this assessment toward the goal of producing RQE by October 15, 2015

4Q 2013 NOC Report – November 12, 2013 • Assessed RFR project's procurement and estimate development • Presented assessment of the 4c Cost Estimate presented to Board • Reviewed scope definition and planning assumptions • Addressed BOP procurement model changes • Assessed Campus Plan Project risks	DR Team's development of the 4c Cost Estimate meets appropriate level of definition; future cost estimates will require increased definition to match the Refurbishment Project's anticipated maturity growth
1Q 2014 NOC Report – March 2, 2014 • Analyzed Project's conformance to goals set by Minister of Energy's Long Term Energy Plan (LTEP) • Updated RFR risks • Provided summary of Project Risk Management • Performed a commercial risk review • Continued Campus Plan Projects' risk assessment	The Refurbishment Project complies with the LTEP though there are some gaps that can be addressed over time; RFR procurement, planning and Class 3 Estimate fell behind schedule and is in recovery mode; Campus Plan Project cost and schedule experienced variances to baseline
2Q 2014 Report to NOC – May 13, 2014 • Performed detailed assessment of Campus Plan Projects' risk and assessment of cost/schedule variances • Reviewed and monitored RFR recovery plan • Provided commercial risk update • Assessed RQE preparation	Campus Plan Projects' variances were caused by initial poor cost and schedule estimates; P&M's management model was flawed; P&M and Refurbishment Projects are responding to challenges and lessons learned from early Campus Plan Projects; RFR is recovering from early delays

With each quarterly report, BMcD/Modus provides NOC and the DR Team with our general observations regarding the Project's top risk areas as well as specific recommendations, as required. In addition, with each report, we provide more granular focus on specific "drill down" issues that were the subject of our prior quarter's activities. From these reports, we provide the DR Team with a series of specific recommendations and observations for their use.

The DR Team has a complimentary process through which it is documenting our recommendations and providing the team's actions needed to close out those concerns. We meet weekly with DR Team's point of contact who updates the log of recommendations and actions, and meet periodically with the Project's leadership team (the "Refurbishment Project Executive Team" or "RPET") as a whole. To date, we have seen the DR Team take action on many of the items we have raised, including: (1) taking the recommendations as written as well as the prescriptive actions we may have identified; (2) finding a middle ground for response and action; or (3) identifying how the DR Team plans to address such recommendations in the future. In our reports, we identify the team's progress and monitor both the sufficiency and the speed of its responses. Thus far, we have been satisfied with the DR Team and P&M organization's actions or commitments to providing responses to our recommendations.

VI. Summary of BMcD/Modus Reports and Current Status Update – 3Q 2013 through 2Q 2014

A. Initial Project Assessment – August 13, 2013

In our August 2013 Initial Project Assessment Report, BMcD/Modus provided NOC with an overview of the Refurbishment Project's status at that time and identified a number of key recommendations for the DR Team to consider. The Initial Assessment Report was intended to form a benchmark for the Project's progress, so it is appropriate to revisit our key observations from one year ago and measure the team's progress:

BMcD/Modus Initial Assessment Report August 2013	Current Status
BMcD/Modus believes the Refurbishment Project was appropriately advanced to support its major goal of producing a Release Quality Estimate ("RQE") for final Board of Directors and Shareholder approval by October 15, 2015. However, we noted that the DR Team needs to effectively and efficiently manage a number of significant risks in order to achieve the necessary level of definition and project maturity required for the RQE.	The Refurbishment Project has made a number of key advancements in the last year and remains on pace with RQE preparation. However, the required effort increases with the passage of time. The team's effort for the 4d Cost Estimate will provide a good indicator of the Project's overall readiness.
The DR Team needs to mature, break down silos and operate as an integrated Project Team for the Execution Phase.	Some progress has been noted in this regard though there is more work ahead. Recent leadership changes will have to be monitored for effectiveness though the leadership remains committed to moving the organization to the Execution Phase. The Project Team should be further optimized in this regard by the award of significant work packages (Containment Isolation and Turbine Generator) to the SNC/Aecon Joint Venture.
The EPC contracting model presents a significant challenge, as this model is new to OPG and will require a number of process and management changes. We noted that the DR Team's current growing pains are commonly experienced by owners who engage in large EPC contracts for the first time.	The P&M Team for the Campus Plan Projects struggled with the initial application of a hands-off oversight model paired with largely cost reimbursable target price contracts with vendors. The DR Team has learned from these early lessons and is moving forward with more active management of the work.
OPG's oversight of the Detailed Engineering and Planning & Assessing phases poses perhaps the most significant near-term risks, as these functions have typically been performed in-house by OPG on past projects. We recommend OPG consider "shoulder to shoulder" work with the EPC design partners to expedite the	Development of Detailed Engineering by the May 2015 deadline remains a milestone at risk. Engineering has modified its approach to a collaborative design process in which the engineering work on-going at vendors' home offices is subjected to OPG's more immediate review and resolution of outstanding issues. The goals for the collaboration are appropriate, though some delays in awarding BOP work are placing the design completion

BMcD/Modus Initial Assessment Report August 2013	Current Status
start of detailed engineering and constructability reviews.	milestone at risk.
OPG's most vital role during the Execution Phase will be to manage and coordinate the work of the multiple EPC contractors, a condition that typically provides a ready source of change orders, delays and commercial disputes on projects of this type.	The DR Team has taken this issue head-on and has instituted a number of key issues and initiatives that assert OPG's role as the integrator and as general contractor. Most notably, OPG has taken control of the detailed Level 3 Project schedule integration and coordination.
The final scope for the Refurbishment Project needs to be fully vetted and properly narrowed to meet the Project's goals of (1) replacement of life-limiting components (such as pressure tubes) and (2) replacement of components most efficiently done in an extended outage.	The DR Team instituted a "Blue Ribbon Panel" to perform an independent review of the Project scope. The Blue Ribbon Panel made several recommendations to remove project scope resulting in less project complexity (as well as reducing project risk) and lower cost. On an ongoing basis, any scope changes are reviewed by the Scope Review Board.

B. 4Q 2013 Report

The focus of this report was to progress the status of the Project from the baseline established by our Initial Assessment Report. In particular, the 4Q 2013 Report looked at the progress and risks of RFR and Balance of Plant, the 4c Cost Estimate, the development of the Project's scope and schedule and Campus Plan. We also reported at that time that the DR Team's senior leadership had positively responded to the recommendations in our Initial Project Assessment that we presented to the NOC in 3Q 2013.

BMcD/Modus 4Q 2013 Report December 2013	Current Status
The RFR Contractor is falling behind schedule for the Tooling and Definition Phase work	OPG's RFR Project Team required the RFR Contractor to develop a recovery plan to restore progress to plan. The RFR contractor's performance has since improved, and although it has not fully recovered the schedule, OPG is much more active in holding the contractor accountable to work its recovery plan and show improved progress.
The Class 3 Estimate for the RFR Project is at risk, and the RFR Contractor's metrics indicate that it is not expending enough hours to meet the Class 3 estimate delivery date in the contract.	The DR Team worked extensively with the RFR contractor to identify and communicate its expectations regarding its Class 3 estimate (which will be a significant input to OPG's own 4d release business plan) and is currently in the process of vetting the JV's estimate, but all indications are that the JV has met its contractual obligation.
The Facilities and Infrastructure Projects that are part of the Campus Plan remain a significant risk to the DR Project, particularly D20 Storage.	The DR Team's senior leadership is taking action to turn the performance around, including: • Additional focus on helping the ESMSA vendors' design partners' efforts by co-locating OPG resources as resident engineers; • Developing a plan to integrate all of the pre-requisite work into a master integrated schedule so that the ESMSA's can properly plan and resource load the work and OPG can manage the contractors' work load and performance. • Completion of work allocation to each of the vendors so that the ESMSA's can properly plan their work
Consider the 4d Cost Estimate that the DR Team will be presenting for next year's Business Plan a "dry run"	The DR Team has agreed with this recommendation and incorporated it into its 4d estimating plan. The 4d estimate

BMcD/Modus 4Q 2013 Report December 2013	Current Status
for RQE.	will be developed over the summer and will be submitted to the Board for approval in the November 2014 Board meeting. Additionally, the DR Team is focusing on improving traceability, sourcing, vetting and suitability of database information underlying the estimate.
Quality and consistency of the materials in Gate packages should be addressed. Gate review packages are often hastily assembled by the project teams and provided to the GRB only shortly before the gate review meetings.	The Refurbishment and P&M leadership have increased accountability by their respective project managers. Recent packages have been subjected to increased scrutiny and initial rejections. Management of both organizations has reiterated quality standards.
The development of the Level 3 schedule needs improvement. Since future contracts (most notably RFR and BOP) are based on target price arrangements, it is essential that the operative schedule is resource loaded; otherwise, the Project Team will lack an essential tool for holding the contractors accountable to their budgets. Project Controls will need management support to hold the work groups accountable for developing and utilizing the Master Schedule, including developing forums for discussion of the Execution Phase Master Schedule status and preparation.	The DR Team has made significant progress and adopted all of BMcD/Modus's recommendations for the development of the Project schedule. The Definition Phase schedule continues to mature and scheduling standards are being enforced with the contractors.
The next challenge for Engineering will be to morph into an organization that can manage the next phases of work, and here remains some concern. Engineering will have multiple roles, from design authority to reviewer of the various EPC contractors' work-product to developing the restart plan for the units. This will require a significant planning effort.	Meeting the May 2015 milestone for completion of detailed design is at risk, though OPG Engineering has taken significant steps by injecting increased front-end planning and collaboration with the vendors. The success of these efforts will be determined over the coming months.

C. 1Q 2014 Report

The issuance of our 1Q 2014 report coincided with the release of the Minister of Energy's December 2013 Long Term Energy Plan ("LTEP"). As a result, much of this report was dedicated to identifying any gaps or misalignment between the Project and the LTEP. Our report also identified recommendations for strengthening OPG's planning for completion of the Release Quality Estimate ("RQE").

BMcD/Modus 1Q 2014 Report March 2014	Current Status
RFR contract incentives and disincentives are based on 4 unit performance; the LTEP prioritizes the success of Unit 2 as a precursor for the other 3 units.	Refurbishment's senior management is committed to a thorough commercial review of the RFR contract's incentives and disincentives. Target price negotiations will provide a platform for negotiation of these essential provisions.
There is ambiguity in pricing risk for the RFR target price; the contract monetizes contingency as part of the target price, not before. This includes focusing on risk and contingency for the Project estimate to be included in the 2014-2015 Business Plan.	With the completion of its Class 3 Estimate, SNC/Aecon has committed to providing input to OPG for modeling contingency for the 4d Cost Estimate. Nonetheless, monetizing the associated contingency for RFR will require substantial effort.

BMcD/Modus 1Q 2014 Report March 2014	Current Status
The DR Team has struggled with defining its "oversight" role of the contractors. OPG needs to embrace "active management" of its contractors and apply lessons learned from early Campus Plan and RFR work regarding benefits of active management vs. passive oversight.	The DR Team and P&M have each made essential changes to their respective management models that incorporated these lessons learned. These changes include: • Increased collaboration for estimating, scoping, scheduling and planning of the work; • Increased vendor surveillance; • Managing the interfaces in the integrated schedule; • Increased management meetings with vendors and senior management to review and resolve open issues.
The DR Team's project controls are in an early stage of development and require testing and validation, including: Continued action on the part of the DR Team to strengthen schedule and budget controls, and continued development of the integrated level 3 schedule.	As noted, this is underway.
With respect to the RFR Class 3 Estimate, OPG needs to hold the RFR contractor accountable for meeting the required schedule dates.	The OPG team held SNC/Aecon accountable for developing a quality product for the Class 3 Estimate. OPG's team challenged multiple aspects of the estimate and required SNC/Aecon to change or further explain multiple elements of the plan embedded in the estimate.
Several Campus Plan Projects may delay breaker open if the delays are not mitigated; the lack of an integrated and resource loaded Level 3 schedule has made it difficult for P&M to evaluate Campus Plan Projects' work priorities, ESMSA resource needs and determine potential delays to the project pre-Refurbishment critical path.	The maturity of the P&M schedules is increasing; there are currently 14 projects with updated level 3 schedules including all work on the critical path. These updated schedules are allowing P&M's management to make appropriate decisions.
Capture lessons learned from Campus Plan and incorporate into management of BOP work in real time.	As noted in our 2Q 2014 Report, this is currently occurring on both the Campus Plan Projects and Refurbishment.
Evidence of P&M mismanagement of EPC contract terms with ESMSA could impact Refurbishment.	Refurbishment immediately injected the lessons learned regarding ESMSA performance. Refurbishment has increased collaboration with the ESMSA vendors and has made decisions regarding scope assignments based on vendor readiness and capability.
Early indicators of scope/pricing for the ESMSA BOP work have been mixed with examples of misunderstood scope and engineering requirements.	The BOP estimates that were initially out of line have been reviewed and scope is being aligned. The Refurbishment Project initiated an Options Review Board ("ORB") that provided additional vetting of scope and planning. The ORB has already uncovered poor initial planning and scoping of three BOP projects.
The Risk Management Program has initiated some improvements but has additional work to do to increase effectiveness; the current Program Management Plan is lacking in detail and clarity.	Risk Management's profile within the Refurbishment and P&M teams still needs to be raised. The Refurbishment team launched an RQE risk session that should increase the teams' focus.

D. 2Q 2014 Report

On May 13, 2014, BMcD/Modus presented to the NOC our Quarterly Report for 2Q 2014 (the "2Q 2014 Report") in which we provide a summary of our investigation of the causes of the cost and schedule variances in the Refurbishment Project's key pre-requisite Campus Plan Projects. This assessment was not initially in our scope, though in early 2014, the DR Team's senior management requested that we provide an independent review of the causes of these cost variances. Our 2Q 2014 Report raised a number of concerns that both NOC and senior management have taken very seriously. During the May 13, 2014 meeting, the NOC requested both BMcD/Modus and the DR Team's executives to provide an update of the issues we each raised regarding the Campus Plan Projects' performance and cost and schedule variances at the next NOC meeting. As part of this update, OPG senior management has asked us to assess:

- The current impact and extent of condition of the variances found in the budget and schedule for the Campus Plan Projects;
- The extent to which changes in management personnel and approach implemented for the Campus Plan Projects have been effective;
- Whether Refurbishment has benefitted from lessons learned from the Campus Plan Projects, and specifically whether the EPC contracting model for Refurbishment and the method OPG has chosen to manage the EPC contractors suffer from the same flaws as seen in the early Campus Plan Projects;
- Whether the Refurbishment Project's and Campus Plan Projects' contractors (in particular the Extended Services Master Services Agreement ("ESMSA") contractors ES Fox and Black & McDonald) are improving in their performance and incorporating lessons learned into their methods for planning, estimating, scheduling and executing the work; and
- Whether the Projects & Modifications ("P&M") and the Darlington Refurbishment organization ("DR Team") are committed to transparent reporting of the Refurbishment Project's progress.

The following is our analysis of these questions. We have been advised by the senior management of the DR Team and P&M that they intend to take into account our findings regarding the issues that impacted the early Campus Plan Projects, and are currently working to implement all of the lessons learned from these projects. We have been involved in several discussions with the DR Team and P&M with respect to their on-going and planned management actions and we have begun to see evidence of these efforts taking effect. Additionally, many of the issues that we identified with respect to the performance of the Campus Plan were the direct result of the fact that the P&M organization had not adopted many of the procedures developed by the DR Team for the Refurbishment Project. The legacy issues that caused the schedule and cost variances for the two key projects—D2O Storage and AHS—will continue to be a challenge, and will need to be closely monitored.

1. Extent of Condition – Budget and Schedule for the Campus Plan Projects

a. Management of the Work

As we have previously stated, the DR Team is responsible for planning and executing the bulk of the Refurbishment Project work. The Projects and Modifications organization is responsible for completing the Campus Plan and other prerequisite projects. It is important to note that Refurbishment and P&M are set up differently from both an organizational and process standpoint. Thus the issues impacting the prerequisite projects have manifested themselves differently and the necessary responses may also need to be different.

Each organization also exhibits a different level of maturity from a project management standpoint. As noted in our 2Q 2014 Report, P&M was an existing maintenance organization that handled minor modification work within the OPG stations. P&M's yearly volume was historically less than $300M. P&M was chosen to manage the Campus Plan Projects because the DR Team was in its embryonic stage. P&M negotiated the ESMSA contracts as generic commercial documents that could be assembled as EPC agreements as needed. In retrospect, had the Campus Plan Projects been in the same general size and complexity as the plant modification work, this plan may have had a greater chance of

success. However, the first of the Campus Plan Projects was D2O Storage, which is as technically and logistically complex as virtually any work on the DR Project, and this project was unfortunately used as a pilot project.

The Refurbishment Project has, from the start, proceeded with its major EPC contracts using a more direct management approach which has been further strengthened by internalizing the early lessons from D2O Storage and AHS and by changes in the senior management team. Since the inception of our engagement in late February 2013, we have witnessed a number of changes by the DR Team that incorporated lessons learned, notably the changes to the method for scheduling the work via a fully integrated Level 3 schedule, increased focus on necessary scope through a robust process with multiple checks and vetting, and adhering to the gate process for budget approval with greater rigor.

Moreover, the EPC contracting method selected for Refurbishment's major scopes of work—the RFR/Containment Isolation, Turbine Generator and Steam Generator projects—has been managed differently and much more effectively than the pilot Campus Plan Projects. Because of their timing, the pre-requisite Campus Plan Projects provided the DR Team with an opportunity to test its new EPC model and draw experience for the much larger Refurbishment effort. Thus, the Campus Plan Projects were intended to be a source of lessons learned. The area in Refurbishment where the lessons learned from D2O Storage and AHS are most salient is the Balance of Plant work: here too, Refurbishment has made essential changes to the procurement method, scope identification and instituted greater collaboration at a much earlier stage than seen from the Campus Plan Projects.

b. Overall Cost Impact

A critical aspect of our 2Q 2014 Report's examination was to identify the extent to which the early problems with D2O Storage and AHS spread and otherwise impacted the Refurbishment Project. From a budget standpoint, while the DR Team is still examining the extent of the cost impacts from each of the Campus Plan Projects, it would appear that approximately 67% of the overall variance from the 4c Cost Estimate approved by the Board in 2013 resides with these two troubled projects. The following chart illustrates the current budget status for the Campus Plan Projects:

Bundle	Project	Release 4C estimate	Current Forecast*
F&IP (Campus Plan)***	D_2O Storage	$110M	$276M**
	OSB Refurbishment	$45M	$53M
	Auxiliary Heating Steam	$46M	$85M
	Water and Sewer	$46M	$58M
	DEC	$87M	$87M
	R&FR Annex	$32M	$41M
	RPO	$89M	$100M
	Electrical Power Distribution	$14M	$13M
	Other F&IP Projects	$83M	$111M
Subtotal		**$552M**	**$824M**

* Current forecast amounts provided by the DR Team.
** The D2O estimate is currently being challenged and confirmed. This is an interim estimate that may not be reflective of the final Estimate at Completion.
*** Does not include SIO Projects

It is important to note that we believe that the majority of the cost increases with D2O Storage and AHS are due to maturation of these projects' scope definition, scope management, unforeseen subsurface conditions or flawed estimates. In other words, the increased budgets are simply reflective of the true project costs had they been estimated properly at the outset. Moreover, we have no issues with the project delivery approach (multiple-prime EPC, target price). We have seen the multiple-prime EPC approach employed successfully on other projects, and it is appropriate for OPG to act as the construction manager and design authority for a refurbishment project on an operating plant. Additionally, target pricing in this context is appropriate—particularly prior to the completion of detailed engineering—a

contractor would add a large premium to accept pricing risk. Our criticism in the 2Q 2014 Report stems mainly from the fact that the project management strategy originally employed by the P&M organization did not match the chosen commercial strategy, as both the multiple-prime delivery method and target pricing requires that OPG be fully engaged as the contract manager of the Refurbishment Project. As a result, P&M did not have the tools to determine the "true" costs of the project from the outset and communicate those costs to the Board of Directors. In particular, the P&M organization made several mistakes with respect to determining the projects' budgets, including:

- "Negotiation" of bid prices which gave a false sense of security regarding the accuracy of the cost estimates—too much emphasis was given to pricing during the bid evaluation phase rather than understanding the scope, execution plan and qualifications of the contractors;
- Assuming, without the proper vetting and review, that estimates provided by the contractors had a certain level of accuracy even though no design was complete and scope was still in flux – this resulted in significantly lower contingency than should have been applied to these estimates; and
- P&M's and the contractors' failure to regularly update the Estimate at Completion (EAC) once changes were known resulted in the budget shock occurring all at once with the presentation of revised Business Case Summaries ("BCSs").

Based on these practices, the budgets initially approved by the Board for D2O Storage ($108M) and AHS ($45.7M) were not sufficient for the planned scope of work. Moreover, had P&M appropriately classified these two project's cost estimates at a Class 5 (-50% to +100%) maturity level, it is very likely that these projects could have entirely avoided an overrun. At a minimum, under the current Refurbishment Project leadership, these cost estimates would not have been presented to the BOD for full funding release until reaching an appropriate level of maturity.

P&M has recognized the problems which caused these budget overruns to occur and is actively working to negate any repeated issues in the estimating of the remaining work. The BCS for AHS that underlies the authorization for additional funds approved by the Board at the May 2014 meeting was developed by ES Fox using sound estimating processes and vetted by OPG in an appropriate manner. Black & McDonald's estimating effort for D2O Storage is ongoing and this estimate is more problematic for reasons discussed herein. The P&M team has increased the level of rigor Black & McDonald applies in its preparation, though despite these efforts, it may take until later this quarter or early 3Q before the estimate is in shape for thorough review. Thus, at this time, P&M is proceeding with appropriate caution in how this estimate is being characterized.

c. Schedule Impacts – D2O Storage and AHS

Due to the extended time used for detailed engineering, and poor planning and scheduling practices deployed by P&M and the ESMSA contractors, there is much less contingency and schedule float available to complete the Campus Plan. While the Campus Plan Projects were initially helped by the one year change in Refurbishment's breaker open date (from October 2015 to October 2016), this additional time was not utilized in an effective manner. However, after the change in P&M's leadership in January 2014, detailed schedules have become a top priority for the Campus Plan Projects. As a result, P&M has more confidence in their time projections and is now able to evaluate ways to improve the schedule for the D2O and AHS buildings.

- The AHS project is currently projecting about 3 months behind schedule which could miss its completion milestone prior to the Vacuum Building Outage ("VBO"). Since our 2Q 2014 Report, P&M has taken action to try to improve these completion dates through:
    - Prioritizing the resolution of any remaining design issues;
    - Working double shifts on critical path work;

- Simplifying the design of the pipe chase to the plant by substituting a very difficult to construct underground pipe chase with an above-ground pipe rack, which should positively impact both the project's schedule and budget; and
- The DR Team is monitoring the schedule progress of AHS and is readying mitigation plans in the event that the VBO milestone cannot be met, including utilizing the existing construction boilers and/or procuring temporary back-up steam capacity if needed.

- D2O Storage remains the more challenging project from a schedule standpoint. The combination of underground utilities and poor soil conditions, significant design changes, engineering delays and contractor performance has pushed D2O Storage to a projected completion of April 15, 2016. This date has no float and is based on a mere 5 ½ months to erect and install the building's key piping systems. The P&M team is currently engaged on a number of fronts in attempts to reduce the complexity of this design and thus ease construction:
  - Value engineering of the piping design including rationalizing the aspects of the design to reduce work and potential productivity difficulties;
  - Elimination of the box drain below the foundation, which should improve the foundation work schedule by 4 weeks;
  - Review and rationalization of the design of the pipe chase to the existing TRF building;
  - Elimination of office space requested by the TRF personnel;
  - Elimination of the emergency back-up diesel generator.

As with the budget, these scope reduction initiatives and the schedule impacts are under review and are being assessed with increasing urgency.

The other Campus Plan Projects are being added to the integrated master schedule at this time. Currently 12 of the 28 pre-requisite projects have been added to the master schedule. Moreover, the projects that have shown potential for schedule variance are being given priority and mitigation plans have been developed to minimize impact. As an example, the Containment Filter Venting System ("CFVS") was initially scheduled to complete prior to the VBO, though, due to design issues, this work was delayed. Based on the schedule and the project's priorities, the team decided that completing this work at a later time posed no risk; thus the cost to accelerate the work was avoided. Similarly, P&M is looking to increase its understanding of the cost and schedule drivers for each project and work within projects to strategically accelerate only where the benefits are tangible.

2. Leadership Changes

The issues with respect to the Campus Plan Projects led to the departure of the VP of P&M in July of 2013. P&M's new leadership has put into place several important initiatives, and is intent on correcting the remaining issues around management and staff, including streamlining internal processes to enhance project performance. In addition, there has been increased accountability and integration between P&M and the Refurbishment Project, with P&M reporting and updating its project schedules and other metrics within the Refurbishment Project's reporting. In addition there has been increased sharing of resources between P&M and the Refurbishment Project: (1) the Refurbishment Engineering team is much more active in attempting to resolve the issues that have impacted design completion within the Campus Plan Projects; (2) a schedule "hit team" has been deployed by Refurbishment to help standardize the schedules for the Campus Plan Projects; and (3) there has been increased integration between the P&M and Refurbishment BOP teams. These measures have increased the DR Team's understanding of the importance of the Campus Plan Projects to Refurbishment and their likelihood of success.

3. Implementation of the Lessons Learned and Corrective Actions

As stated above, in order to put our 2Q 2014 report into the appropriate context, it is important to understand that the DR Team and P&M are two separate organizations within OPG. The DR Team is focused on planning for the successful

execution of the refurbishment and life extension of the four Darlington units. They are a single program organization that have implemented a very methodical approach to determining the Refurbishment Project's scope and implemented project management procedures and controls that meet our expectations for what we would typically see in the industry. P&M is a projects organization set up to manage a large portfolio of capital projects for both Pickering and Darlington. As such, the needs of the P&M organization are different to Refurbishment and it does not utilize the same procedures and controls developed for the Refurbishment Project. The P&M processes are geared towards multiple (hundreds) of small projects authorized within the OPG AIS-C funding stream. Due to the fact that the Campus Plan Projects had to start significantly ahead of the Refurbishment Project, and the fact that the DR Team did not have its construction execution organization in place, the Campus Plan Projects were handed over to the P&M organization to manage. Therefore, many of the issues experienced by P&M were never a threat to the Refurbishment Project, as appropriate controls had been developed.

As an example, one of the causes of the increased project estimates for Campus Plan is the increase and changes to scope. In contrast, our prior reports have documented the fact that the DR Team has taken a balanced approach to the development of the Refurbishment Project scope. The initial scope identification effort incorporated scope beyond that of refurbishment and life extension, potentially increasing the budget and project complexity. However, to even this out, the DR Team has continuously monitored and repeatedly tested the included scope through scope reviews and de-scoping exercises, including a detailed and intensive effort led by the Blue Ribbon Panel in 2013. Additionally, the DR Team has monitored scope definition through the Gate Review process and Health of Scope metrics. B&McD/Modus believes the DR Team has struck an important balance between overly limiting scope (and risking scope growth during execution) and being overly-inclusive (and risking excessive project budgets).

The Refurbishment Program has benefitted from the early start of the Campus Plan Projects because it has allowed Refurbishment to evaluate its management processes and procedures and make adjustments as necessary. It is not uncommon for an organization to have to adjust its commercial strategies, project delivery methodology, contractor incentive/disincentive structure, or other negotiated contractual provisions during the course of a long and complicated project to ensure that commercial considerations continue to drive the appropriate contractor behavior. Good project management organizations make such adjustments based upon the information that is known to them. As a result, we would expect that the DR Team would incorporate the lessons learned from the Campus Plan experience—and there is evidence that they are doing so—even before the issuance of our 2Q 2014 Report.

Below is an update as to the most significant issues raised in our 2Q 2014 Report. We have recorded the responses from both the DR Team and P&M, as there will necessarily be differences between the required planned management actions. For Refurbishment, the main actions are to implement the lessons learned and ensure its model will not be subjected to the same issues as seen with the Campus Plan Projects. For P&M, it will be to recover the on-going projects and to mitigate future risks.

BMcD/Modus D2O Storage and AHS Findings	Refurbishment Approach	P&M Recovery
Scope for the projects was based on a performance specification; P&M relied on the contractors to develop and progress the design.	Scope for the EPC contracts is based on thorough Modification Design Packages (MDPs) developed by OPG Engineering and its OSS vendors; MDPs advance the design beyond the conceptual stage and provide the EPC contractor with a defined scope of work.	P&M has also adopted the MDP as the basis for scope definition for its remaining projects. OPG Engineering is fully engaged in developing, vetting and approving design work.
Contracts were bid between the two ESMSA vendors and low price was deemed the primary consideration for	Major EPC contracts were openly bid and qualifications, technical ability and performance record trumped price; after considering the subcompete used	Most of P&M's work was subjected to the sub-competitive bidding process; however, the packages each ESMSA vendor received after the

BMcD/Modus D2O Storage and AHS Findings	Refurbishment Approach	P&M Recovery
award.	by P&M for the Balance of Plant work, the DR Team changed its process to directly assign the work packages based on vendor qualifications.	initial pilot projects were more reflective of each contractor's capability.
P&M negotiated the cost reimbursable prices resulting in reduction of the base cost estimate prior to full scope definition.	Vendor pricing for the EPC contracts is being determined from a progression of cost estimates at prescribed points in project definition; final negotiation of target price contracts will only occur once the scope is known and estimates have matured.	P&M has abandoned previous practices and is now working collaboratively to develop reasonable cost estimates.
P&M misclassified the D2O Storage and AHS initial bids as "Class 2" and "Class 3" caliber estimates prior to the start of design work, which resulted in severe underestimation of project contingency.	Refurbishment built the classification of the estimates into the process for weighing the EPC contractors' progress; as an example, the RFR contractor has yearly (from 2011 to 2015) prescribed deliverables of Class 5/4/3/2 estimates that accompany different levels of the project's maturity. Moreover, contingency development is occurring under a defined interactive process in which OPG and the vendor must agree on risks, opportunities and monetization of those potential events.	P&M is following the Refurbishment gate process.
P&M's team was instructed to be "hands-off" and allow the contractors to develop their designs, and only after full development would P&M and the OPG stakeholders provide comments, changes and design input; this led to scope creep and an attenuated design process that has eliminated construction float.	Refurbishment has increased management focus and collaboration on engineering solutions, and is moving up critical constructability and design review cycles. As an example, the final price for RFR will be negotiated on the basis of final construction work packages and proving-out of the critical tool and construction operations in a full scale mock-up that simulates actual conditions.	P&M is instituting a collaborative approach to engineering reviews.
P&M presented the cost estimates it received as part of business case summaries for full project funding release at a very early phase of design definition.	Refurbishment is incrementally releasing funds through a gate process that measures progress on the basis of objective criteria and will seek full funding release only when the scope is fully defined, execution planning is completed and all risks are well-known.	P&M is adopting the Refurbishment gate process and will not submit projects for full release until a reliable estimate is prepared. P&M has chosen to hold off presentation of the revised D2O Storage BCS until it has confidence in the underlying estimate's accuracy.

BMcD/Modus D2O Storage and AHS Findings	Refurbishment Approach	P&M Recovery
As design and project definition progressed, the contractors and P&M failed to timely update the projects' cost estimates at completion (EAC), and only provided such updates when additional funds were necessary.	Refurbishment's gates and the yearly Business Plan cycles require the projects to update EAC on a timely basis. In recognition of the issues with D2O Storage and AHS, Refurbishment is imposing additional controls to require constant evaluation of each projects' maturity.	P&M has abandoned this practice and its team has been instructed to update EAC when new information is available.
Scope creep into these projects caused the design to become more complicated and difficult to build.	Refurbishment has instituted an Options Review Board chaired by the SVP that evaluates whether the maturing design meets the Project's needs.	P&M is currently engaging in value engineering reviews of the major projects to determine whether scope reductions are possible.
P&M gave the contractors complete latitude to develop their Project schedules and did not adequately vet these schedules' quality.	After initially considering a siloed Project schedule, Refurbishment is adopting a much more rigorous method of vetting and integrating the projects' schedules into a single, detailed Level 3 schedule that, once fully developed, will represent all of the work in the Execution Phase; Refurbishment is enforcing quality standards from each of the vendors.	P&M is instilling rigor into the schedule process and requiring the vendors to develop Level 3 schedules that depict their plans for the work. These schedules are being integrated with the Refurbishment schedules and must meet the same quality standards.
As an artifact of the poor practices that established and updated project budgets, P&M's reporting was inaccurate and not fully updated to reflect project status.	Refurbishment is establishing processes for data fidelity in its reports and continues to improve the quality of the reporting.	P&M is revamping its entire suite of metrics to align with the requirements of Refurbishment.
P&M managed the work in "silos" and didn't regularly engage the contractors in meaningful dialogue intended to remove barriers and fix problems.	Refurbishment is establishing multiple forums for interaction with the contractors. Each major contract has a Steering Committee made up of project executives that meets monthly, and the major EPC contracts engage in CEO-level meetings each business quarter.	P&M has instituted Steering Committee meetings as well as a monthly ESMSA Summit in which OPG and the two contractors can air any issues in an open manner.

The P&M and Refurbishment organizations have taken action to acknowledge the Campus Plan Projects' issues and incorporate lessons learned into their planning activities. However, implementation of these lessons learned and the related actions will take an on-going concerted effort that will not happen overnight. In fact, as P&M is working through all of the Campus Plan Projects to develop and vet proper estimates and schedules, additional issues may be uncovered. This will also require a high level of monitoring to ensure that the recovery efforts are successful.

Exhibit 1

3Q 2013 Initial Project Assessment Report

Supplemental Report to
Nuclear Oversight Committee
2nd Quarter 2014

Darlington Nuclear Refurbishment Project

This entirety of this report was filed at

L-4.3-1 Staff-072, Attachment 1, pp. 8-112

Exhibit 2

4Q 2013 Report

Supplemental Report to Nuclear Oversight Committee

2nd Quarter 2014

Darlington Nuclear Refurbishment Project

This entirety of this report was filed at

L-4.3-1 Staff-072, Attachment 2

Exhibit 3

1Q 2014 Report

Supplemental Report to Nuclear Oversight Committee

2nd Quarter 2014

Darlington Nuclear Refurbishment Project

This entirety of this report was filed at

L-4.3-1 Staff-072, Attachment 3

Exhibit 4

2Q 2014 Report

Supplemental Report to Nuclear Oversight Committee

2nd Quarter 2014

Darlington Nuclear Refurbishment Project

This entirety of this report was filed at

L-4.3-1 Staff-072, Attachment 4

Project Excellence Initative

The purpose of this document is to summarize the Project Excellence Initaitive Steering Committee (SC) roles and responsibilities as well as the role of each supporting Working Team (WT).

This document includes the following:

Table of Contents

TERMS OF REFERENCE Project Excellence Steering Committee	Issue Date: August 25, 2016

TERMS OF REFERENCE – PROJECT EXCELLENCE STEERING COMMITTEE

1. Background

Over the next 10 years and into the foreseeable future, OPG will continue to invest significantly in projects to sustain plant operations and as a primary vehicle for company growth. In recognition of this, the Executive Leadership Team (ELT) requested that an **Enterprise Level Initiative** be undertaken with a goal to improve project outcomes across OPG. As a result of this, a **Project Excellence Steering Committee** has been established to oversee a number of iniatitives, via Working Teams, that will contribute to this goal.

2. Objectives

The primary objectives of the Project Excellence steering committee is to oversee the individual initiatives undertaken within the Project Excellence framework and to 1) ensure that the working teams are adequately resourced to perform their work, and 2) provide direction and oversight to the team as they establish their objectives and deliver on their goals.

3. Scope

This initiative involves and applies to all organizations across OPG that execute projects and includes all aspects of delivering projects in order to achieve **Project Excellence**.

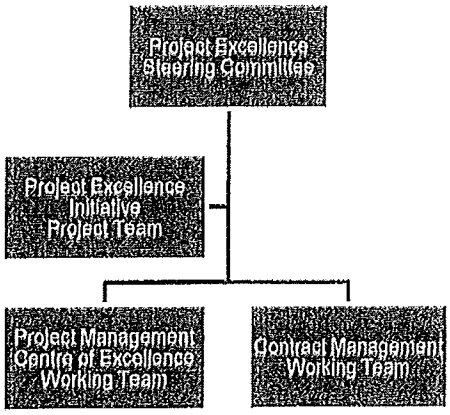
4. Approach/Strategy

For each major initiative, a **Working Team** (WT) will be established with the responsibility for developing a Project Management Plan for the initiative and for planning and coordinating activities necessary to produce the deliverables.

Each major initiative will have its executive sponsor(s) who are also members of this Steering Committee.

A change management lead will be assigned to the project to facilitate this change.

Currently, two Working Team's have been established. Others will be added when needed as determined by the Steering Committee.



5. Timing

This initiative on Project Excellence commenced in January 2016 and will continue through to the end of 2017 at which time it will be evaluated to determine whether the initiative should be extended or continued to be managed as part of the Project Management Centre of Excellence (PM CoE).

TERMS OF REFERENCE Project Excellence Steering Committee	Issue Date: August 25, 2016

6. **Deliverables**
   Deliverables will be identified at the Working Team level.

7. **Key Stakeholders**

   Project governing bodies such as the Gate Review Board (GRB) and the Asset Investment Screening Committee (AISC), as well as all organizations that execute projects, are considered key stakeholders of this initiative. As such, the deliverables and output of the initiative are intended to enhance the project management processes that support these bodies in fulfilling their roles.

8. **Committee Meetings**
   - Bi-Monthly Steering Committee commencing in August 2016.
   - Bi-Weekly Working Team meetings rotated at different lead locations. The Working Teams will report out at each Bi-Monthly Steering Committee meeting.

9. **Team**

   Steering Committee:

   - D. Reiner, SVP Nuclear Projects (Co-Sponsor/ Chair)
   - M. Martelli, President RGPM (Co-Sponsor/ Chair)
   - G. Jager, Nuclear President & CNO
   - B. Keenan, SVP People, Culture & Communications
   - S. Martin, SVP Business & Admin. Services
   - Ken Hartwick, SVP Finance Strategy Risk and CFO

   Project Excellence Initiative – Project Team

   - G. Rose, VP Project Planning & Control – Nuclear Projects (Co-Chair)
   - P. Burroughs, Director Project Management - RGPM (Co-Chair)
   - M. Attong, Refurbishment, Manager Planning & Control (Program Manager)
   - Jennifer Ankrett (Change Management)

   Working Teams

   - Each Working Team will be responsible for its own resources.

Approval:

Dietmar Reiner, SVP Nuclear Projects — Aug 29, 2016 Date

Mike Martelli, President, Renewable Generation & Power Marketing — Aug 29, 2016 Date

TERMS OF REFERENCE **Project Management Centre of Excellence (PM CoE) Working Team**	**Issue Date:** August 25, 2016

PROJECT MANAGEMENT CENTRE OF EXCELLENCE (PM CoE) WORKING TEAM

1. Background

As part of the **Project Excellence** initiative, the Executive Leadership Team (ELT) requested that a key strategic initiative be undertaken to implement a **Project Management Centre of Excellence (PM CoE)** with a goal to improve project outcomes across OPG.

2. Objectives

The primary objectives of the **PM CoE Working Team** are to develop and recommend to the **Project Excellence Steering Committee** strategies for establishing:

- A **common, scalable project delivery model** for all projects across all business units that focus on delivering projects safely, at the required quality, on time, and on budget, with all project goals met.
- A **Project Management Centre of Excellence** organization model where project management expertise, best practices, tools, processes and lessons learned are available to all OPG projects.

Once the recommendations are accepted by the **Project Excellence Steering Committee**, the **PM CoE Working Team** will develop a plan and implement the approved strategies.

3. Scope

This initiative involves and applies to all organizations across OPG that execute projects.

4. Approach/Strategy

The Working Team (WT) will be established with the responsibility for developing a Project Management Plan for the initiative (Program). The WT will also be responsible for planning and coordinating activities necessary to produce the deliverables. Key aspects of the strategy being considered for the PM CoE initiative are outlined in Appendix A.

Recommendations for implementation will be presented to the **Project Excellence Steering Committee** for approval. Upon approval, the WT will lead the implementation.

A change management lead has been assigned to the Project Excellence initiative to facilitate the changes being made by each Working Team in a common manner.

5. Timing

This initiative on Project Excellence commenced in January 2016 and will continue through to the end of 2017. The work of this WT began in May 2016 and will culminate with the official launch of the PM CoE on July 1, 2017. Once established, the PM CoE will be an ongoing function within OPG.

6. Deliverables

A list of deliverables and milestones for this initiative is included in Appendix B.

7. Committee Meetings

- Bi-Weekly Working Team meetings rotated at different lead locations.

8. Team

Project Management Centre of Excellence (PM CoE) Initative Executive Sponsors:

- D. Reiner, SVP Nuclear Projects (Co-Sponsor)
- M. Martelli, President RGPM (Co-Sponsor)

TERMS OF REFERENCE **Project Management Centre of Excellence (PM CoE) Working Team**	**Issue Date:** August 25, 2016

Working Team

- G. Rose, VP Project Planning & Control – Nuclear Projects (Co-Chair)
- P. Burroughs, Director Project Management - RGPM (Co-Chair)
- M. Attong, Refurbishment, Manager Planning & Control (Program Manager)
- Project Organizations:
  - K. Kaczmarczyk (RGPM)
  - Kim Bosselle and Mike Benjamin (CIO)
  - Terry Doran (Real Estate)
  - Jerry Keto (Decommissioning)
  - Terry Chong (P&M)
- Support Staff:
  - Silviu Idita (People & Culture - Training)
  - Silvester Wong (Investment Planning)
  - Darlene McVeity (People & Culture)

Approval:

Dietmar Reiner, SVP Nuclear Projects — Aug 29, 2016 Date

Mike Martelli, President, Renewable Generation & Power Marketing — Aug 29, 2016 Date

TERMS OF REFERENCE **Project Management Centre of Excellence (PM CoE) Working Team**	**Issue Date:** August 25, 2016

Appendix A: Approach/Strategy

Key aspects of the PM Centre of Excellence initiative will involve establishing:

- A **Common, Scalable Project Delivery Model** for all projects across all business units to enable the delivery of projects that consistently meet Safety, Quality, Schedule and Cost goals. This includes:
  - Establishing cost and schedule **baselines** and **managing changes** to plan.
  - **Common** processes, tools, portfolio/program/project tracking and reporting. **Management control and oversight** throughout project lifecycle.

- A **PM Centre of Excellence** organization model to support that includes:
  - A **common knowledge base** comprising industry best practices, processes and tools, including the use of benchmarking, and provides a forum for network/ support for PMs.
  - **Centres of Expertise** for estimating, scheduling, cost management, risk management, other critical areas – with expert project resources in place to support projects.
  - **Quality Standards** - quality criteria and expectations for the project management framework, processes and documents.
  - **Competencies Development** – PM Development and training for core project roles including Project Managers, Risk Managers, Schedulers, Estimators, Cost Managers.
  - A **model for providing Project Services** to projects across OPG, including assignment of **specialized resource support** for core project roles on projects.
  - **Continuous Improvement** – periodically assessing the effectiveness of key processes and activities, identifying improvement opportunities/ gaps, and implementing actions to address.
  - **Project Excellence Culture** – a culture of excellence that enables and motivates stakeholders (internal and external) to apply their knowledge and abilities for the success of the project.

TERMS OF REFERENCE **Project Management Centre of Excellence (PM CoE) Working Team**	**Issue Date:** August 25, 2016

Appendix B: Deliverables and Milestones

#	Deliverable	Milestone
1	Develop a Corporate Level Policy on Project Management.	August 15, 2016
2	Governance Review/gap analysis performed and Implementation Roadmap including supporting IT Strategy developed. Includes assessment of governance against CII and other best practice.	September 30, 2016
3	Set of Program metrics established. Includes determining methods for measuring performance improvement.	September 30, 2016
4	Common Cost and Performance Management Tool and Reporting in place.	Nuclear – Q3, 2016 OPG – Q2, 2017
5	Project Manager Capability Program Rolled out Across OPG.	Q3 – Q4, 2016
6	Establish CoE including centres for cost management/ estimating, scheduling, risk management, other critical areas.	Q1 2017
7	Quality Standards - quality criteria and expectations for the project management framework, processes and documents.	Q1 2017
8	Common knowledge base comprising industry best practices, processes and tools. Include the use of benchmarking.	Q2 2017
9	Common governance in place across OPG. Considered as a Program Launch point.	July 1, 2017
10	Peer Review performed.	August 30, 2017
11	Continuous Improvement process covering initiatives at the Enterprise, BU and major Project level.	Q4 2017, Ongoing

TERMS OF REFERENCE Contract Management Working Team	Issue Date: August 25, 2016

CONTRACT MANAGEMENT WORKING TEAM

1. Background

As part of the **Project Excellence** initiative, a sub-initiative will be undertaken to review how OPG develops contracting strategies, manages the execution and administration of contracts, and closes out contracts. A **Contract Management Working Team (Working Team)** is being established to perform this review.

2. Objectives

The primary objectives of the Working Team are to:

1) Assess North American industry for Contract Management models
2) Select the best model for OPG,
3) Recommend the "best" model to the Project Excellence Steering Committee.

Once a model is accepted by the Steering Committee, the Working Team will:

1) Perform a gap assessment of the 4 models currently used within OPG,
2) Make recommendations to close the gaps with the preferred model. At a minimum, this will include recommendations for Contract Management Governance, Oversight, Support, and Performance models.
3) Develop an implementation plan.
4) Assist the Line Organizations with the Implementation.

3. Scope

This initiative involves and applies to all organizations across OPG that execute Projects and perform Contract Management.

4. Approach/Strategy

To achieve the objectives, the Working Team will:

- Assess industry practices and recommend a scalable Contract Management Model for use by all project executing organizations within OPG.
- Define, determine and establish processes for effective Contract Management (including Administration) of contracts within OPG, integrated with the Project Management framework being implemented by the Project Management Centre of Excellence (CoE) Working Team, including scalability to different project types, sizes, and risks.
- Consider the application of Contract Management tools, like Ecosys, to effect efficiency, transparency, and predictability in the overall project management process.

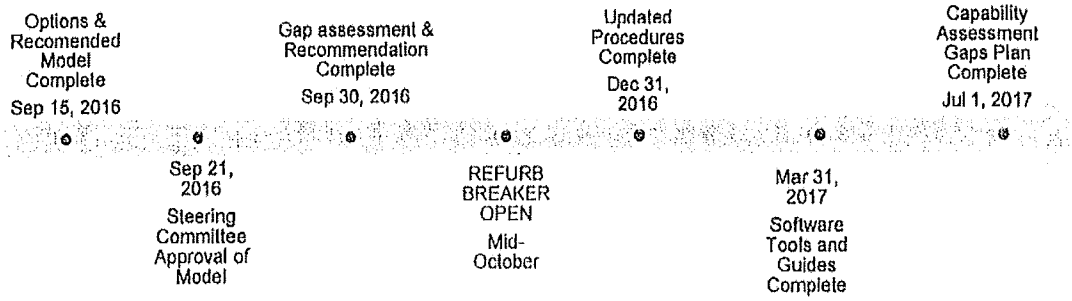
Recommendations for implementation will be presented to the Project Excellence Steering Committee for approval. Upon approval, the Working Team will assist the Line Organizations with implementation.

The Project Excellence initiative will provide a Change Management Lead to facilitate the changes in the Implementation Plan in a common manner.

5. Timing

The work of this Working Team will begin in August 2016 with a target complete implementation across OPG of July 1, 2017. A number of steps, for the Darlington Refurbishment Program only, pre-date Breaker Open in mid-October 2016. The timeline is shown in the line diagram below.

TERMS OF REFERENCE Contract Management Working Team	Issue Date: August 25, 2016



6. Implementation Plan

A list of deliverables is included below. This list will be refined as the Working Team performs their work.

#	Deliverable	Milestone
1	Recommended Contract Management Model including roles and accountabilities and where they reside. Includes consideration as to how this integrates with the Project Management Centre of Excellence.	September 15, 2016
2	Gap assessment of current OPG practices against the Contract Management Model and recommendations to close.	September 30, 2016
3	Updated Contract Management procedures. Selected software tools confirmed.	December 31, 2016
4	Approved Contract Management guides / instructions for software tools.	March 31, 2017
5	Contract Management capability development assessment and plan.	July 1, 2017

7. Team

Contract Management Initative Executive Sponsor:

- S. Martin, SVP Business & Admin. Services

Working Team

- P. Reinert, VP Supply Services OPG Projects (Chair)
- G. Rose (Nuclear SPOC)
- P. Burroughs/ K. Kaczmarczyk– (RGPM SPOC)
- M. Attong (Integration)
- E. Prokopieva (Legal SPOC)
- L. Saagi (Finance SPOC)
- Terry Doran (Real Estate SPOC)
- Kim Bosselle/ Mike Benjamin (CIO Observers)

TERMS OF REFERENCE Contract Management Working Team	Issue Date: August 25, 2016

Approval:

Scott Martin, SVP Business and Administrative Services — Date

UNDERTAKING J15.4

Undertaking

To provide the terms of reference for the Asset Investment Screening Committee, both the earlier version of the Terms of Reference and the updated one.

Response

The terms of reference for the Asset Investment Screening Committee (AISC) currently in effect is provided in Attachment 1 to this response.

The AISC terms of reference in effect during the prior hearing (EB-2013-0321) was set out in an Appendix A- Business Unit Project Decision Committees to N-PROC-AS-0039, also attached to this response as Attachment 2.

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Guideline

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Title:
TERMS OF REFERENCE - ASSET INVESTMENT SCREENING COMMITTEE

Terms of Reference - Asset Investment Screening Committee

N-GUID-00120-10016-R000
2016-04-19

Order Number: N/A
Other Reference Number:

Internal Use Only

Prepared By:

19 Apr 16

Dwight Zerkee — Date
Senior Manager
Investment Management

Approved By:

25 APR 2016

W.S. Woods — Date
Senior Vice-President - Nuclear Engineering
& Chief Nuclear Engineer

Guideline

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Title:
TERMS OF REFERENCE - ASSET INVESTMENT SCREENING COMMITTEE

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Guideline

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Sheet Number: N/A	Revision Number: R000	Page: 3 of 10

Title:
TERMS OF REFERENCE - ASSET INVESTMENT SCREENING COMMITTEE

Revision Summary

Revision Number	Date	Comments
R000	2016-04-19	Initial issue.

Guideline	Internal Use Only		
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	Sheet Number: N/A	Revision Number: R000	Page: 4 of 10

Title:
TERMS OF REFERENCE - ASSET INVESTMENT SCREENING COMMITTEE

Purpose

This document provides the terms of reference for the Asset Investment Screening Committee, which assists the Chief Nuclear Engineer in managing the *Nuclear Operations OM&A, Capital, Intermediate & Low Level Waste Provision, and Used Fuel Storage Provision Project Portfolios.* The process for review and approval of individual projects and changes to the portfolios is described. Adherence to this procedure shall ensure expenditures are validated with respect to business objectives, *project* priority ranking and feasibility of success.

This procedure does not apply to Darlington Refurbishment *project portfolios*

1.0 DIRECTION

The management of the *Nuclear Operations OM&A, Capital, Intermediate & Low Level Waste Provision, and Used Fuel Storage Provision Project Portfolios* at the fleet level is the responsibility of the President, OPG Nuclear and Chief Nuclear Officer (CNO), who has delegated day-to-day management to the Chief Nuclear Engineer (CNE).

The CNE relies on the assistance the Asset Investment Screening Committee (AISC) in decision making as related to the *Nuclear Operations Project Portfolios.*

The *Asset Investment Screening Committee* (AISC) is a senior management committee with representation from the generating stations and supporting business units. The AISC provides a forum to review the project approval packages and project change approval requests in order to:

- Challenge the proposed solution and feasibility.
- Challenge the proposed cost and schedule of the proposal.
- Challenge readiness to proceed to the next project phase.
- Determine the overall fleet priority and schedule for proposals.
- Approve a recommended schedule for investments.
- Recommend approval of business cases to the appropriate approval authority.

In conducting challenges to project solutions, feasibility, cost, schedule and readiness to proceed, the committee fulfills the role of Gate Review Board as documented in N-MAN-00120-10001 Sheet GRB Nuclear Project Gated Process.

The AISC manages the *Nuclear Operations Project Portfolios* through:

- Approval of additions, including new project starts and emergent projects, for the upcoming business planning period.
- Approval of requested changes in project budgets and milestones.
- Approval of release of project contingency.
- Recommendation of project deferrals and cancellations to maintain spending within approved limits.
- Monitoring the completion of Project Closure Reports and Post-Implementation Reviews.
- Recommendation of improvements to the Project Portfolio management and processes.

Collectively, this committee shall provide the senior management review of business risk to the fleet and prioritize the project portfolio to minimize that risk.

1.1 Structure and Membership

The Senior Management sponsor for the AISC is the President, OPG Nuclear and Chief Nuclear Officer (CNO). The Senior Management representative and Chair of the committee is the Chief Nuclear Engineer (CNE). The committee membership is:

- CNE (VF)
- Vice President, Nuclear Finance (V)
- Vice President, Engineering Strategy (V)
- Vice President, Projects and Modifications (V)
- Vice President, Planning & Controls (V)
- Director Station Engineering, Pickering (V)
- Director Station Engineering, Darlington (V)
- Director Design Engineering (V)
- Director Engineering. Inspection and Maintenance Services (V)
- Director, Nuclear Waste Engineering (V)
- Director, Components Engineering (V)
- Director, Equipment Reliability (V)
- Senior Manager, Investment Management

(V) Indicates a voting member of the committee

(VF) Indicates a voting member and final decision making authority

Representatives from other organizations may be invited to participate in AISC meetings in order to address Project Portfolio additions pertinent to their organization or provide advice as needed.

1.2 Quorum

Quorum for the committee is 10 of 12 voting members or delegates being present. Delegates should be at the Band G level or if at a lower level empowered to make decisions on behalf of the representing organization. The voting committee members shall review the proposed project approval packages and recommend to the Chair the disposition of the business case (approve, approve with actions, defer or return for further development).

1.3 Meeting Frequency

Routine AISC meetings are held monthly and will be scheduled for at least three hours in duration. Additional meetings may be scheduled to address issues or higher numbers of BCS than can be handled in the regularly scheduled meetings.

A tentative schedule of meetings for the year will be published on the AISC SharePoint site. Meeting dates will be finalized three months before their scheduled dates; however, these are subject to change depending on CNE availability.

1.4 Agenda and Meeting Materials

The agenda for the routine AISC meetings will follow a standard format:

- Review of Minutes and Actions from previous meeting
- Review of AISC Operational & Financial Metrics
- Review of Project Change Requests
- Review of Project Approval Packages
- Any other business

Additionally, selected Post-Implementation Reviews will be presented to communicate important lessons-learned from completed projects.

An example of the standard agenda is found in Appendix A.

The agenda will be prepared and published on the AISC SharePoint site no later than the Friday preceding the scheduled date of the meeting. An email with a link to the SharePoint site will be sent to the Voting Members to notify them that the agenda has been published.

Meeting materials are to be submitted to Investment Management no later than Noon of the Wednesday preceding the scheduled date of the meeting.

1.5 Outputs and Deliverables

The AISC shall provide the following outputs and deliverables:

- Recommend approval of the BCS to the appropriate OAR authority. This recommendation is communicated by the CNE signing the AISC Part B: Decision Record N-FORM-10994 accompanying the BCS.
- Prioritize the OPG Nuclear Operations Project Portfolio consistent with the additions and budgetary envelope over a rolling 5 year period
- Assign the portfolio additions to the accountable execution organization
- Approve an implementation schedule for the proposal
- Approve Project Change Requests requesting changes in budget, schedule or release of contingency.

- Maintain minutes of meeting that describe the rationale of why a particular proposal was approved, approved with action(s), rejected, deferred, or returned for further development
- Provide feedback to the submitting organizations to allow continuous improvement on the quality of their submissions
- Recommend improvements to the Project Portfolio management and processes.

1.6 Dispute Resolution

If the Sponsoring Business Unit disputes the decision made by the AISC, the Business Unit may request a review by the CNO. Upon review of rationale for the decision, the CNO may overturn a decision made by the AISC by directing the CNE in writing to accept or modify the priority/schedule of the proposal including the rationale for the reversal of the decision.

2.0 DEFINITIONS AND ACRONYMS

2.1 Definitions

Business Case Summary is a summary document that provides sufficient information for decision-makers to evaluate, rank and approve or reject an investment.

Nuclear Operations Project Portfolio describes a collection of OM&A, Capital, and Provision projects that have been approved for implementation by the AISC as well as potential projects under review for cost estimating and approval. Selection criteria include consideration of current business drivers, priority, availability of resources and feasibility (in terms of time, skills and access).

Project is defined as a temporary endeavor undertaken to create a unique product or service where,

- Incremental cost per unit is greater than $200k.
- Execution duration is limited, with defined start and finish dates.
- Work is clearly incremental to ongoing work, non-repetitive in nature, recurring at an interval of less than every 6 years.
- Sponsorship and management accountabilities can be clearly defined.

Project Approval Package is defined as a collection of documents, including the Business Case Summary, which provides assurance that the project is ready to proceed to the next project phase.

2.2 Abbreviations and Acronyms

AISC - Asset Investment Screening Committee
BCS - Business Case Summary
CNE - Chief Nuclear Engineer
CNO - Chief Nuclear Officer

OAR - Organizational Authority Register
OM&A - Operation, Maintenance and Administration
OPG - Ontario Power Generation
SVP - Senior Vice President
VP - Vice President

3.0 RECORDS AND REFERENCES

3.1 Records

Record Created	Associated Form Number	QA Record? Y/N	Filing Information/Retention (PASSPORT Type/Sub-Type)
AISC Part A: Issues Characterization	N-FORM-10765	No	RRA 2005006
AISC Part B: Decision Record	N-FORM-10994	No	RRA 2005006
Project Change Request Authorization	N-FORM-10607	No	RRA 2005006
Type 1 Business Case Summary	OPG-FORM-0074	No	RRA 2005006
Type 2 Business Case Summary	OPG-FORM-0075	No	RRA 2005006
Type 3 Business Case Summary	OPG-FORM-0076	No	RRA 2005006
Forecast Over-Variance Approval	OPG-FORM-0074	No	RRA 2005006

3.2 References

3.2.1 Performance References

- N-STD-AS-0028 Project Management Standard
- N-MAN-00120-10001 Sheet GRB Nuclear Projects Gated Process
- OPG-STD-0076 Developing and Documenting Business Cases

3.2.2 Developmental References

Project Prioritization for Nuclear Plant Investments: Lessons Learned from Other Industries. EPRI, Palo Alto, CA: 2008. 1016733

Appendix A: Sample AISC Agenda

ASSET INVESTMENT SCREENING COMMITTEE			
CHAIR	CNE		
ATTENDEES	VP Engineering Strategy Director , PN Engineering Director, DN Engineering	VP Nuclear Finance Director IMS Engineering Director NWM Engineering	VP Projects & Modifications Director Components Eng Director Design Engineering
	Director Equipment Reliability	Senior Manager, Investment Management	
PURPOSE	To review the Nuclear Project Portfolio status and requested changes.		

AGENDA

Item	Topic	Duration	Lead
1.	**Review of Minutes and Actions**		CNE
2.	**AISC Operational & Financial Metrics** **a) Portfolio Health** **b) Portfolio Status** **c) PCRAF Summary**		Finance
3.	**PCRAF Review**		Finance
4.	**Project Approval Package Review**		
	DN Project		Director DN Eng
	DN Project		Director DN Eng
	PN Project		Director PN Eng
	PN Project		Director PN Eng
	Nuclear Engineering Project		VP Components Eng
	IMS Project		Director IMS Eng
5.	Any Other Business		Finance
6.	Review New Actions		Finance

DURATION	3.0 hours	TBD	08:00 – 11:00
LOCATION			

ONTARIO POWER GENERATION

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Nuclear Procedure

TITLE

PROJECT AND PORTFOLIO MANAGEMENT

AUTHORIZATION

SINGLE POINT OF CONTACT:	R. Habib Director, Projects and Modifications
AUTHORIZATION AUTHORITY:	M. Peckham Vice President, Projects and Modifications
COMPLIANCE DATE:	Immediate

PURPOSE

The procedure provides direction for Project and Funding Release Management to the Project Sponsor and Project Manager to define the problem, and plan and execute the resolution using project management (PM) principles.

This procedure also provides direction to the Project Manager regarding PM activities which include interfacing Business Processes within the Project Life Cycle, their deliverables, and important work sequence hand-offs.

Project Funding is allocated from:

- The Nuclear Portfolio for use by Projects & Modifications (P&M) and Inspection, Maintenance & Commercial Services (IM&CS).
- Provision for use by Nuclear Waste Management Division (NWMD).
- Nuclear Refurbishment (NR) Program for use on Nuclear Refurbishment Projects.

This procedure receives its authority from N-PROG-AS-0007, Project Management.

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Title:
PROJECT AND PORTFOLIO MANAGEMENT

EXCEPTIONS

When this procedure specifically describes steps for Portfolio funded projects, NWMD is exempt from those steps.
When this procedure specifically describes steps for NWMD, the other organizations noted in this procedure are exempt from those steps.
Projects transferred from NR for execution by P&M may have applicable exceptions as outlined in Section 1.4.

Table of Contents

1.0 DIRECTION

As each project is unique and complex in its own way, the management of a project and the approval of the funding is a graded, risk based approach in accordance with the Ontario Power Generation (OPG) Management Systems.

This procedure gives direction for the following:

(a) Projects funded from the Nuclear Operations Project Portfolio (hereafter known as Portfolio).

(b) Projects funded from other sources.

(c) Project terminal points.

(d) Project Life cycle and its phases.

(e) Role of interfacing organizations that support the project.

(f) Project schedule milestones aligned with the outputs of stakeholders.

(g) Specific PM deliverables required to be completed at the end of an individual project phase in order to satisfy the approval requirements of the associated *decision gate*. These deliverables align with the following principles:

(1) Definition Package, which defines the project's work. This is typically the Project Execution Plan (PEP). The level of rigour required to define the work in the PEP is dependent on the level of project risk and complexity.

(2) Authorization Package, typically a Business Case Summary (BCS), which recommends to the approving Organizational Authority Register (OAR) authority, the release the funds needed to perform the work defined in the PEP.

Note: Authorization Package may include a Board Memorandum if the approval of the OPG Board of Directors is required.

1.1 Project Management

For the purposes of this procedure, the Project Manager of a project is typically a Stratum III position.

1.1.1 All work performed during a project should:

(a) Implement the OPG Management systems described in N-CHAR-AS-0002, Nuclear Management System.

(b) Be executed by qualified staff.

(1) NWMD funded projects in association with W-TQD-400-00002, Nuclear Waste Management Division Engineering Support Personnel Training and Qualification Description.

(2) Portfolio funded projects in accordance with N-QG-403-00023, Nuclear Project Staff Qualification Guide.

(c) Non-conformances to the implementation of the OPG Management systems such as failures, malfunctions, deficiencies, deviations, or abnormal occurrences should be managed in accordance with N-PROG-RA-0003, Corrective Action.

(d) Be directed through Business Unit (BU) *Decision Gates* in accordance with the applicable BU Decision Committees noted below.

(1) Portfolio - Asset Investment Screening Committee (AISC).

(2) NWMD - Project Investment Screening Committee (PISC).

(3) NR - Program Scope Review Board (PSRB) or Gate Review Board (GRB).

1.2 Projects Funded By the Portfolio

1.2.1 Management of the Portfolio should be based on the following principles:

(a) Chief Nuclear Officer (CNO) has responsibility for the Portfolio at the fleet level.

(b) Day-to-day management of the Portfolio at the fleet level is delegated to the Chief Nuclear Engineer (CNE).

(c) CNE relies on the VP of P&M, as well as the Directors of Nuclear Finance - Investment Management, Plant Design, IM&CS, and P&M to assist in the Portfolio decision making process as members of the AISC.

(d) Oversight of the Portfolio at the facility level is the responsibility of the Business Unit Vice President (BU VP). BU VP may create committees within the BU to provide challenges, analysis, and advice. Such committees may be in the form of screening committees (e.g., Site Screening Committee [SC]) and approval committees (e.g., Site Project Approval Committee [PAC]).

1.2.2 Funding in the Portfolio should be divided into the following two categories:

(a) <u>Released</u>

The amount approved for expenditure through the approval of a BCS by the appropriate level of authority in accordance with OPG-STD-0017, Organizational Authority Register (OAR), as well as the amount identified to be required to complete the project. Cash flows are typically included in the Portfolio excluding contingency.

(b) Unallocated Funding

The difference between the total business plan target (ceiling) within the Portfolio and the sum of Released project amounts. The Unallocated category contains project candidates, but does not constitute a portion of the approved Portfolio until funding is released through a BCS.

1.2.3 Projects may have unique funding release strategies with corresponding *decision gates* which require different forms of management reviews and approvals.

1.2.4 The following principles apply to Projects funded by the Portfolio:

(a) Projects over $200k per unit should engage the AISC for Portfolio approval.

(b) Minor projects are under $200k per unit and the process to approve these projects should be managed by the authorizing Director.

(c) VP, P&M provides project oversight to Commercial Facility projects.

(d) Constructed Minor Fixed Assets (CMFA) with projects greater than $500k for the design and construction of engineered tools should be used to support operations and maintenance.

(1) CMFA projects executed by IM&CS are governed by I-PROC-MP-0001, Engineered Tooling Modification Process.

(2) CMFA projects executed by all other business units are governed by N-PROC-MP-0090, Modification Process.

(e) Projects that impact the Design Basis are Engineered Changes and should be processed in accordance with N-PROC-MP-0090.

1.3 Projects Funded by Provision Budget

1.3.1 Management of the Nuclear Waste Provisional Project Portfolio should be based on the following principles. For details see W-PLAN-08100-00002 Nuclear Waste Management Division Project Investment Steering Committee (PISC) Terms of Reference.

(a) CNO shall be responsible for oversight of provision funding of the Nuclear Waste Management Portfolio.

(b) Management of the NWMD project portfolio shall be delegated to the Vice President, Nuclear Waste Management Division (VP-NWMD).

(c) The VP NWMD shall rely on the NWMD Project Review Committee to provide challenge, analysis, and advice. Approval of projects and annual budget changes, including use of contingency, shall remain within limits established in the Business Plan.

(d) Conceptual funding for the Initiation phase is requested using N-FORM-10945, Cost Estimate and Request for Conceptual Funding.

(e) NWMD Operation Maintenance and Administration (OM&A) and Capital projects that are not funded from the Provision Portfolio should be brought to the AISC for disposition.

1.4 Projects Funded by Nuclear Refurbishment

NR projects executed by P&M are externally funded by the NR organization from the NR Program budget. The transfer of work from NR to P&M is in accordance with N-GUID-09701-10014-R000, NR - Transfer of Work Process. The aspects of the guide that are applicable to P&M follow either Scenario 1 or 2. Refer to the guide for full details.

1.4.1 NR projects executed by P&M should be categorized as either Non-Chartered (Scenario 1) or Chartered (Scenario 2) projects. The differences and exceptions to this procedure are listed in Table 1 below.

Table 1, Exceptions for Nuclear Refurbishment Projects executed by Projects and Modifications

Non-Chartered Project (Scenario 1)	Chartered Project (Scenario 2)
Is considered a sub-project of a larger *NR Project Bundle.*	Is considered a *NR Project Bundle* or standalone project.
Does not have a project charter however a Needs Statement shall be provided by the NR Project Manager.	Requires a formal Project Charter.
Is managed by a P&M Project Manager with additional oversight provided by the applicable NR Project Manager.	Is fully managed by a P&M Project Manager.
P&M should seek funding from the applicable NR Project Manager using N-FORM-11466, Project Authorization Package (PAP).	P&M should seek funding directly through the NR Gate Review Board (GRB) following N-INS-09701-10005, Nuclear Project - Gated Process. The authorization package is a BCS in accordance with OPG-STD-0076.
For Initiation/Conceptual Phase Funding (Gate 1), the P&M Project Manager should submit N-FORM-11454, OBU Funding Request, to the NR Project Manager for approval.	For Initiation (conceptual) Phase Funding (Gate 1), the P&M Project Manager should submit an Initiation BCS to the NR GRB. If applicable, any Identification Phase funding required by P&M should be requested with N-FORM-11392, Funding Request Form, and approved by the NR GRB (Gate 0).
For Change Management, use P&M N-FORM-10607, Project Change Request Authorization Form (PCRAF) and process (Section 1.9 of this procedure).	For Change Management, follow N-PROC-LE-0010 and N-INS-00120-10022, NR - Cost and Schedule Change Control, using N-FORM-11252, NR Change Control Form.
Change management PCRAF forms should be submitted to the applicable NR Project Manager for approval.	Change management forms should be submitted to NR for approval in accordance with N-INS-00120-10022.
The approved funding contingency should be released from NR to the VP of P&M. Contingency drawdown is controlled internally within P&M using the PCRAF process (Section 1.9).	Management of Contingency should be in accordance with N-PROC-LE-0013 - NR Contingency Management.

1.5 Projects Funded From Other Sources

Projects funded from other sources should be governed by the PM Principles described in N-PROG-AS-0007, Project Management, Appendix A – Project Management Principles.

1.6 Project Terminal Points

1.6.1 For the purposes of defining the limits of Project Scope, project terminal points should use the Engineered Change terminal points whose interfacing work may impact the site Design Basis, or non Design Basis, or Commercial Facility.

1.6.2 Interfacing Design Authorities at the site (i.e., Power plant, NWMD, or Commercial Facility) should make the terminal point agreements. Disagreements should be managed in accordance with N-PROC-HR-0018, Resolution of Differing Professional Opinions.

1.7 The Project Life Cycle Phases and Decision Gates

The Project Life Cycle should be managed through the following phases:

(i) Identification Phase

(ii) Initiation Phase

(iii) Definition Phase

(iv) Execution Phase

(v) Close Out Phase

(vi) Post Implementation Review (PIR).

The present phase deliverables and the plan for the next phase are reviewed at a specific management *Decision Gate* and typically only after Gate approval is the project allowed to advance to the next phase. *Decision gates* often include a request and approval of funding for the next project phase(s). Figure 1 illustrates the typical project phases, major *decision gates* and associated funding approvals.

Figure 2 illustrates the possible Identification Phase streams which are dependent on the type of project and executing BU. Figure 3 illustrates the balance of the typical project phases. Figures 2 and 3 also indicate the typical main *decision gate* and phase relationship.

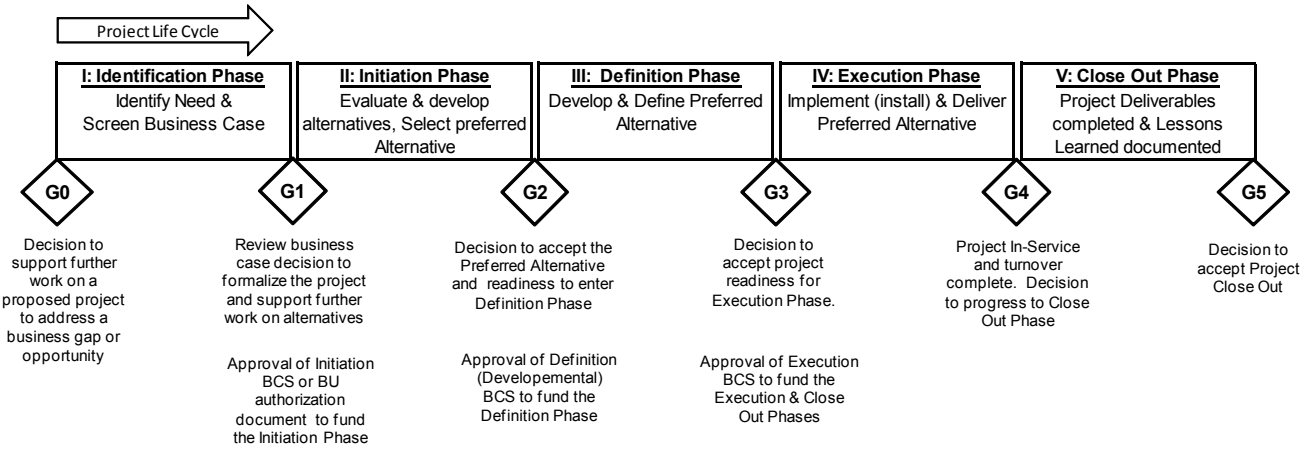

Figure 1, Typical Project Phases and Decision Gates

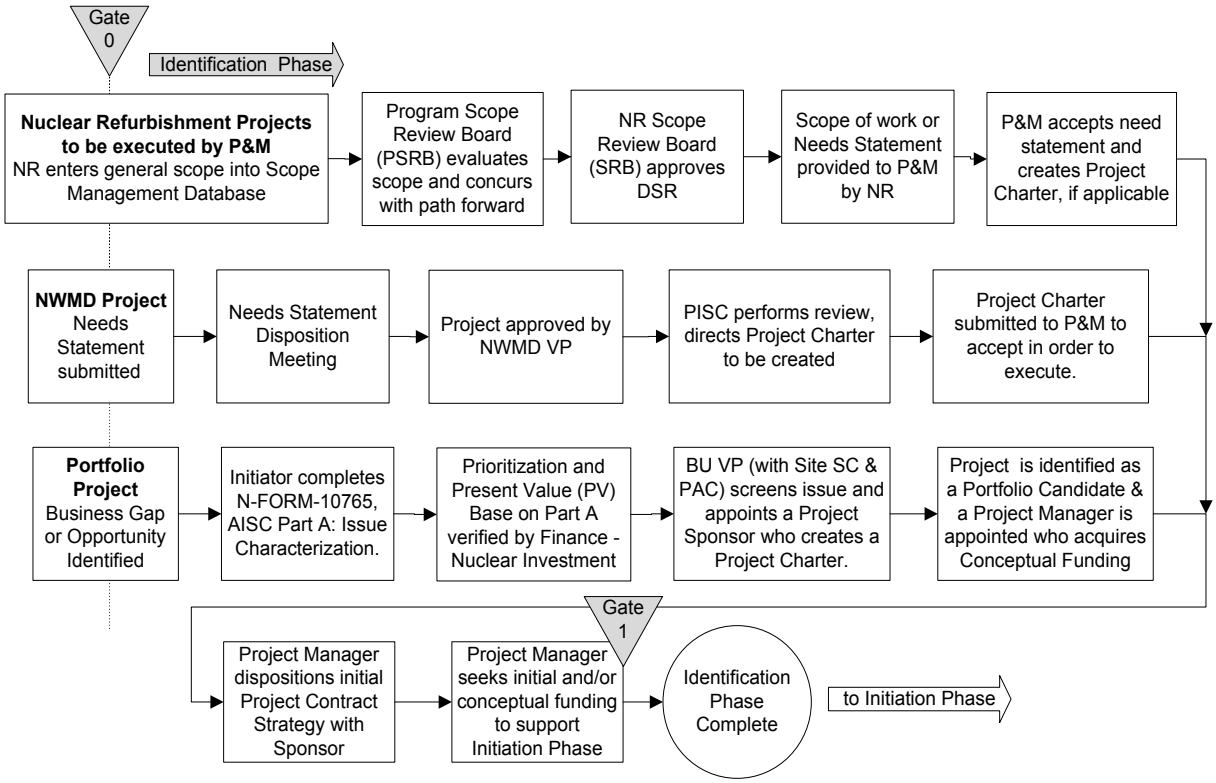

Figure 2, Project Identification Phase with potential streams.

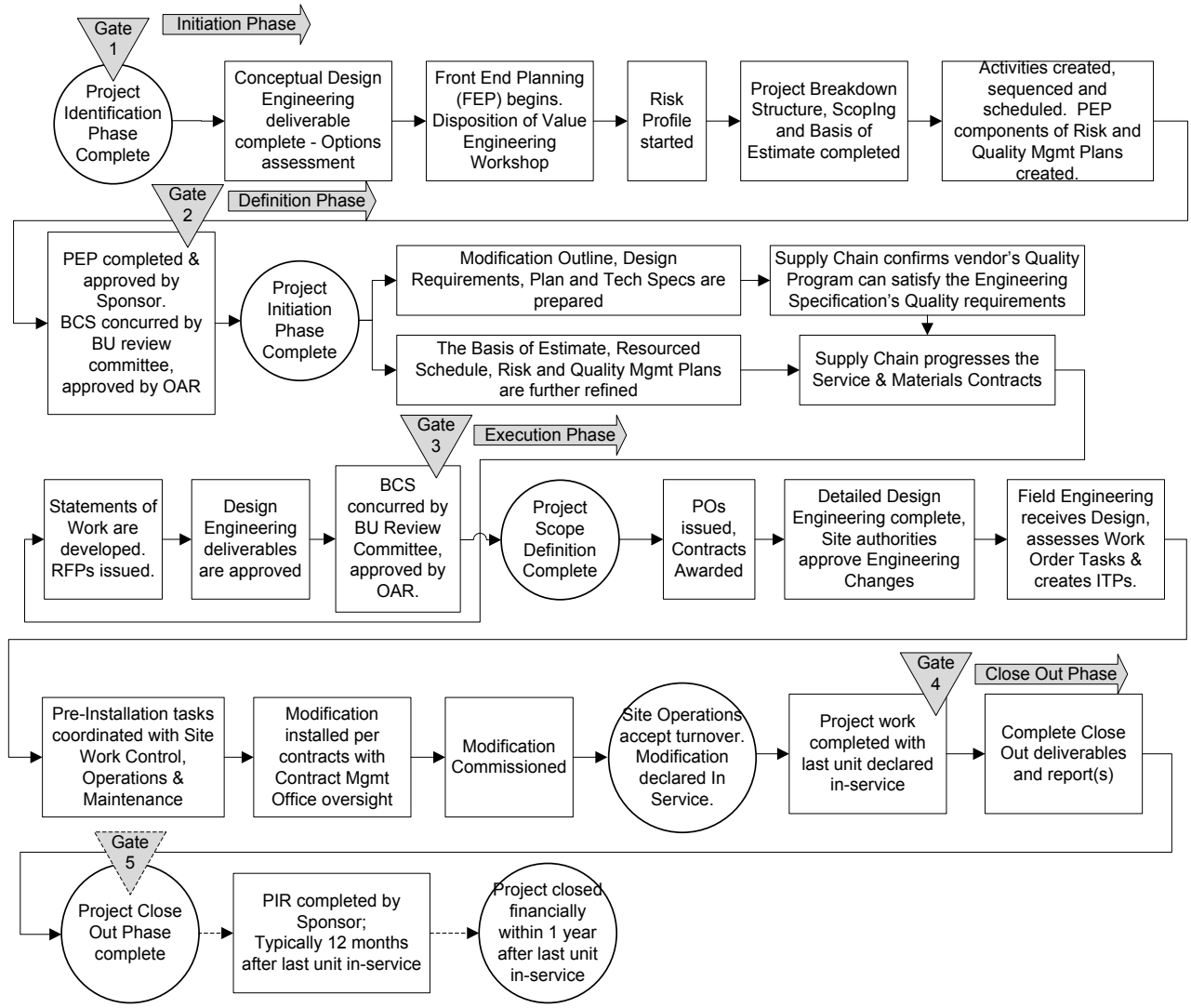

Figure 3, Typical Project Phase Flow Chart

1.7.1 Identification Phase

The purpose of the identification phase is to identify and assess the business gaps or to identify opportunities to enhance performance.

The output of this phase includes a placeholder in the BU budget for the proposed project.

Project Sponsor should document the business gaps or opportunities which are generally identified through one or more of the following methods:

- System health reviews
- Analysis of component failures or facility needs
- Life Cycle Management Plans
- Review of non-standard work programs
- For NWMD, the release of monies to the executing group, in accordance with PISC direction in support of the 5 year Business Plan.

1.7.1.1 When the business gap cannot be closed with existing resources and requires Portfolio funding, the following is required:

(a) BU VP should concur with the project scope.

(b) Project Sponsor should develop the statement of need, typically using N-TMP-10117, Project Charter.

(c) BU Decision Committee confirms path forward and directs the PM organization to execute the work.

(d) *Authorizing Authority of the executing organization* should review and accept the Project Charter or Needs Statement, and appoint a Project Manager.

(e) The Project Manager and Project Sponsor should disposition the initial project contract strategy.

(f) Project Manager should acquire conceptual funding to support unfunded activities during the development of the project concept.

1.7.1.2 For a minor project less than $200k per unit, proceed to Subsection 1.7.2.1.

1.7.1.3 For Portfolio projects greater than $200k per unit:

(a) Project Sponsor should perform the following:

(1) Identify the need to the BU VP.

(i) Nuclear Portfolio project candidates require the completion of N-FORM-10765, AISC Part A: Issue Characterization in consultation with their local Business Support staff and/or with staff in Nuclear Finance Investment Management.

(ii) NWMD Portfolio project candidates require completion of N-FORM-11491, NWMD Needs Statement.

(2) Decide whether the issue may be resolved and managed by the OM&A funding for the base organization, or whether the issue or implementation strategy is too complex, and therefore the services of a dedicated project organization is required.

Note: BU Decision Committee may be consulted to assist with the decision.

(3) Create a Project Charter using N-TMP-10117.

(4) Approve the Charter and forward the approved Project Charter to the *Authorizing Authority of the executing organization*.

(b) Authorizing Authority of the executing organization should perform the following:

(1) Review the Project Charter, if acceptable, sign acceptance in order to proceed.

(2) Appoint a Project Manager.

(c) Project Manager should perform the following:

(1) Forward the approved Project Charter to Business Services – Controlled Documents for issuance into PASSPORT, with a copy to the executing organization.

Note: For P&M Division, the copy goes to the Project Management Office (PMO).

(2) Acquire conceptual funding for organizations that do not have OM&A Base funding by completing N-FORM-10945.

(d) Project Sponsor should ensure a project can be listed on the budget year's 'New Project Start List' by submitting the following documents to Nuclear Finance – Investment Management no later than June 30 of the previous year. The following documents are complete at the end of the Identification Phase.

- N-FORM-10765 approved by the BU VP (N-FORM-11491 for NWMD)
- N-TMP-10117 approved by the Project Sponsor and accepted by the *Authorizing Authority of the executing organization*
- N-FORM-10945 approved by the BU VP or delegate.

1.7.2 Initiation Phase

The main purpose of the Project Initiation Phase is to develop viable alternatives which resolve the business gap through the FEP processes.

A graded, risk based approach is used in selecting the FEP processes and tools. The required rigour of PM and controls are a function of the project risk and the expected dollar value of the project. Low risk, low dollar value projects require a lower level of PM and project controls compared to projects with higher dollar value and/or risk. High risk, high dollar value projects require the most detail and the highest level of PM and project controls.

Phase deliverables include the following:

(a) Project Manager should prepare a PEP using one of the following:

- Use N-FORM-11172, Project Execution Plan Form, for projects using the FEP process
- Use N-TMP-10119, Project Execution Plan, for projects not using the FEP process.

(b) Project Sponsor should review and, if acceptable, approve the PEP.

Note: In the case of a Regulatory Commitment (REGC) which requires the involvement of several organizations, the PEP should be approved by the cross over

Note: Manager of those organizations (i.e., the Project Executive Sponsor).

(c) Project Manager should perform the following:

(1) Develop a summary level business case that justifies total project value, and requests funding to further design engineering, finalize scope, acquire vendor quotes, etc. This is typically a BCS. Refer to OPG-STD-0076 and OPG-STD-0017.

(2) If the value of the project release or the anticipated cost of a partial release exceeds $25M (including contingency), prepare a Board Memorandum with the assistance of Nuclear Finance – Investment Management to obtain Board of Directors approval.

(3) Ensure the BCS and Board Memorandum are routed to the Enterprise Leadership Team for review and Chief Executive Officer (CEO) approval no later than three weeks before the Nuclear Operations Committee meeting which is held prior to the full Board of Directors meeting.

(4) For Portfolio funded projects, complete N-FORM-10994, AISC Part B: Decision Record, for projects funded from the Portfolio.

(5) Submit the following to the BU Decision Committee (i.e., AISC, PISC or PGRB):

- BCS or equivalent
- Board Memorandum (for +$25M projects only)
- Completed N-FORM-10994 (for P&M only).

Note: Refer to Appendix A for details.

1.7.2.1 Portfolio Funded Minor Projects

Minor projects of a similar nature are typically grouped together and funded as a program with oversight from a divisional Director. For example, Site minor projects are overseen by the Station Engineering Director, who should also be the Project Sponsor.

Note: This project phase is the entry point for projects valued **less** than $200k into the Project Life Cycle. The previous Project Life Cycle steps are not necessary.

Minor projects should be managed in accordance with the following principles:

(a) Minor Projects That Impact the Site Design Basis

(1) Modification Team Leader (MTL) should define the project work that impacts the Plant Design Basis to the level of rigour required in accordance with N-PROC-MP-0090, or BU Engineering Change Control (ECC) governance.

(2) Director of executing organization should review the proposed work and, if acceptable, provide approval in order to proceed.

(3) MTL should develop and acquire funding approval using N-FORM-10945 (for P&M).

(b) Minor Projects That Do Not Impact The Site Design Basis

(1) Project Manager should define the project work.

(2) Director executing organization should review the proposed defined work and, if acceptable, provide approval to proceed in accordance with Provincial and National Engineering Standards.

1.7.2.2 Development and Progression of the Business Case Summary

Project Manager should perform the following:

(a) Create the applicable BCS in accordance with OPG-STD-0076. The BCS is identified by both project phase and release type:

(i) Project Phase includes:

- Initiation
- Definition
- Execution.

(ii) Release Type:

- Partial (there will be more than one BCS in a particular phase)
- Full (there is only one BCS planned in a particular phase)
- Superseding (BCS re-issue for additional phase funding)

(b) Obtain BCS approval per OPG-STD-0017 OAR.

(c) For any variances to the BCS during the execution of the project, obtain approval from the Director of Nuclear Finance in accordance with OPG-STD-0017.

1.7.2.3 Progression of the Business Case Summary to the Decision Gate

(a) Project Sponsor should submit the BCS for approval to the approving OAR authority for the release of funding following a BU Decision Committee approval to proceed.

(b) Nuclear Finance – Investment Management should provide guidance regarding what supporting documents are required to accompany the BCS, such as the completed PEP, and the level of approvals required in accordance with OPG-STD-0017.

Note: When a project is in response to a proposed REGC, the BCS should be approved by the approving OAR authority prior to the committing of OPG to the REGC.

(c) Project Manager should forward a copy of the approved BCS and associated documents to Nuclear Finance Investment Management and file originals in the PM File.

(d) Nuclear Finance Investment Management should be the single point of interface for further approvals required according to the OAR (e.g., with Finance - Corporate Investment & Asset Planning).

1.7.2.4 Major Interfaces and Handoffs in the Project Initiation Phase

Project Manager should monitor and facilitate the progress of the PM activities described below that are delivered from other organizations.

(a) <u>Conceptual Design Development</u>

(1) Project Manager should perform the project kick off meeting(s) and cursory field walk down(s) to support the development of the Conceptual Design. The walk down(s) should be performed with representatives from implementing and supporting organizations such as:

- Design Team Leader (DTL)
- Contract Management Office (CMO)
- System Engineering
- Field Engineering.

(2) DTL should coordinate the Design Engineering deliverables which at the end of this project phase includes the issuance of:

- Conceptual Design Report and Options
- Assessment forecast of required Design Engineering resources
- Design Agency Engineering Specifications, Scope of Work, and Design Agency Interface Agreement (DAIA) (DAIA for P&M only).

(b) Project Management Activities

Project Manager should perform the following:

(1) Construct a plan and schedule from the Conceptual Design deliverables and describe them in the PEP.

(2) Use the FEP process to ensure the project deliverables described in the PEP are aligned with the Project Sponsor's business gap described in the Project Charter. The Project Manager may use N-FORM-10959, Design Scoping Checklist as a guide to ensure consideration has been given to the interests of the various groups who might be impacted by the project.

(3) Use the Value Engineering (VE) process in accordance with N-INS-00120-10019, Value Engineering. VE should be used when one or more of the following criteria are met or if the Project Manager believes it is required:

(i) Probable project budget with contingency is greater than $5M.

(ii) Project scope is ambiguous.

(iii) There is more than one viable alternative.

(4) Use the FEP processes described below to develop the PEP:

- Project Scoping
- Project Definition Rating Index (PDRI) (if required)
- Risk Management in accordance with N-INS-00120-10014, Project Risk Management
- Basis of Estimate (BOE) and Project Estimating in accordance with N-INS-00100-10000, Project Cost Estimating Instruction
- Scheduling
- Budgeting (cash flow determination).

Note: For details refer to the FEP Section found in the P&M FEP web site.

1.7.2.5 Expediting Projects

To quickly resolve equipment obsolescence or implement ECC defined non-complex improvements, the Project Manager may be requested by the Project Sponsor to expedite the Project Life Cycle.

The Project Life Cycle process is intertwined with various other OPG Management Systems such as:

- Design Engineering
- Supply Chain
- Work Control
- BCS development
- OAR.

All these organizations have their own specific process timelines. These process timelines need to be accounted for when developing an expedited project schedule. It is advised to acquire formal agreements, commitments, cooperation, and prioritization of process timeline exceptions and resources to improve the chances of expedited project success.

1.7.2.6 Milestones Achieved in the Project Initiation Phase

Project Manager should monitor and facilitate the progress of the PM activities that are delivered from other organizations in accordance with the milestones described below.

(a) Design Engineering – (Conceptual Design Phase)

(1) Modification Outline drafted.

(2) Conceptual Report/options assessment issued.

(3) Design contracting strategy developed.

(4) Long lead material requirements defined for major equipment.

(5) Design resources, schedule forecast for overall project.

(6) Engineering Target Completion Date (TCD) commitment for Preliminary Design.

(b) Stations Operation Work Control: for details refer to:

- N-PROC-MA-0013, Planned Outage Management
- N-PROC-MA-0022, Integrated On-Line Work Scheduling
- N-INS-06931-10001, On-Line Cycle Planning Process.

(c) Project Schedule Milestones may include:

- PEP - PEP approved (Key Milestone)
- ASC - AISC disposition (Key Milestone) (if applicable)
- DBC - First BCS approved
- DCA - Design contracts awarded (Key Milestone).

Note: For details see the P&M web site. Milestone acronyms are typically linked to the various departments for their specific use and are not to be referenced in Section 3.2 of this document.

1.7.3 Definition Phase

The purpose of the project Definition Phase is to define the scope of the preferred alternative. The responsibilities of updating any changes to the Definition and Authorization Packages are described in the earlier phase.

Project team should further develop the project scope, cost, schedule, and design engineering in accordance with first BCS funding release strategy, and *Decision Gate* requirements.

1.7.3.1 Major Interfaces and Handoffs in the Project Definition Phase

Project Manager should monitor and facilitate the progress of the PM activities described below that are delivered from other organizations.

(a) Design Engineering work with Design Agency Resources

(1) Project Manager should acquire the following:

(i) Contract Administrator services and DTL assistance to implement the DAIA.

(ii) Design engineering services in accordance with the appropriate Supply Chain procedures.

(2) Project Manager should document in the PEP the provision for design engineering contract administration and interfaces for the design of the project's Systems, Structures and Components (SSCs).

(3) Project Manager as Contract Owner or Design Agency Contracts should develop a Statement of Work (SOW), and Design Agency Engineering Specifications. The Project Manager may use N-FORM-10959 and FIN-MAN-CM-002, Technical Contractor Management Process Manual, as a guide to this PM activity.

(b) Configuration Management

Project Manager should coordinate a configuration management review involving the *paper plant* and *physical plant* of the affected Systems, Structures and Components (SSC) and document non-conformances in accordance with N-PROG-RA-0003.

(c) Development of Project Management Deliverables

Project Manager should coordinate the development of PM deliverables in accordance with the following principles:

(1) Alignment of the Site authorities' approval criteria with the project's general design principles required to achieve dependable performance.

(i) Project Sponsor's BCS PIR plan.

(ii) Director of the accepting organization's Available for Service (AFS) acceptance criteria.

(iii) Commissioning Specifications in accordance with the Engineering Specifications from the Design Engineer.

(2) Maintenance Strategy ensuring the dependability of the new equipment after the project has been turned over to the Site.

(i) Name of Accepting organization's Maintenance Manager.

(ii) Maintenance strategy concurrence in accordance with N-GUID-00120-10001, Nuclear Integrated Supply Planning.

(iii) Transfer of project materials inventory from the project Financial Asset Classification (FAC) to the maintenance organization's FAC.

(3) Operational Strategy describing the optimal use of the new equipment in accordance with availability targets after the project has been turned over to the Site, including name of the accepting organization's operations manager, for concurrence of the Operations strategy.

(d) Supply Chain and Project's Trades Contract Strategy

(1) Project Manager (as requisitioner) should perform the following:

(i) Confirm with Supply Chain the estimated value of the trade's contract(s) in accordance with OPG-PROC-0058, Procurement Activities.

(ii) Contact Supply Chain for the establishment of a Cross Functional Sourcing Team if the estimated value is greater than $5M.

(iii) Develop the Trade contract's Scope of Work. The Project Manager may use Contractor Management Process manual as a guide.

(2) Project Manager should document in the PEP the provision for trade contract administration and interfaces for the installation of the project's SSCs.

(3) Project Manager should acquire agreement regarding the appointment of staff to the Contract Management roles of Contract Owner, Contract Administrator, and Contract Monitor.

For Portfolio funded projects, the following groups are typically utilized to fulfill those roles:

(i) Contract Owner - To be determined through discussions between the Project Manager, Field Engineering, and the CMO prior to the issue of the Purchase Order (PO). The project manager is often the Contract Owner.

(ii) Contract Administrator - Typically First Line Managers (FLM) Construction from Site CMO.

(iii) Contract Monitors - Typically Project Technicians from Field Engineering who have been assigned to the CMO.

(4) DTL should forward the material purchase Quality Assurance (QA) Program information to the Supply Chain Buyer.

(i) For Portfolio and Refurbishment funded projects, the QA Program information is typically documented in N-TMP-10019, Engineering Specifications.

(5) Project Manager should resolve jurisdictional boundary issues by forwarding the Contract Strategy for review and comment to:

(i) Nuclear Operations

- Portfolio funded projects - Maintenance Support: Power Worker Union Work Assignment Single Point of Contact (SPOC)
- NWMD – NWMD Human Resources.

(ii) P&M – PMO Society Purchase Service Agreement (SPOC).

(e) <u>Contracts through the Extended Services Master Services Agreement (ES MSA)</u>

The Extended Services Master Services Agreement Request for Work instruction details the process for acquiring project material and/or services from an ES MSA contractor.

(f) Long Lead Material

The following guidance may not be applicable to Engineer, Procure, Construct (EPC) contracts:

(1) Project Manager should perform the following:

(i) Oversee the gathering of information regarding project material requirements and timing, and identify Long Lead materials.

Note: In accordance with Work Control governance, any material that requires more than 90 days to acquire is a Long Lead Item.

(ii) Ensure material technical performance specifications and QA requirements are created by the Design Engineer for input by the Supply Chain Buyer into the Request for Quotation (RFQ) or (RFP).

Note: Project Manager may use the N-FORM-10959 as a guide to review the RFQ or RFP for completeness.

(iii) Ensure selected vendors and contractors are on the Approved Suppliers List (ASL).

Note: A vendor not on the ASL may require to be audited by Quality Services, which may take 6 months or more.

(iv) Ensure goods or services obtained from outside of Canada are reviewed by the OPG Customs department (details are in the OPG Finance website).

(v) Ensure AFS meeting requirements are met in accordance with BU ECC procedures.

(g) Project Definition Rating Index Workshop

Project Manager should conduct a PDRI workshop for projects greater than $5M prior to progressing to the next *decision gate*. P&M PMO is available to assist and facilitate.

Note: Note: For the PDRI Workshop to be effective there is a minimum quorum requirement. The following people representing their organization should be in attendance for the duration of the workshop with the authority to speak for their organization:

(1) Project Sponsor (minimum Stratum IV) or delegated authority

(2) Project Manager or Project Leader

(3) DTL representing Design Engineering

(4) Accepting organization (typically from operations and/or maintenance).

(h) Business Case Summary Screening; Business Unit Decision Committee Concurrence

(1) Project Manager and Project Sponsor should forward the draft BCS and supporting documents to the BU Decision Committee.

(2) With BU Decision Committee concurrence, Project Sponsor should submit the BCS to the appropriate OAR authority for approval.

1.7.3.2 Milestones achieved in the Definition Phase

Project Manager should monitor and facilitate the progress of the PM activities that are delivered from other organizations in accordance with the milestones described below.

(a) Design Engineering – DES Milestone (Preliminary Design Complete)

- N-FORM-10958, Modification Outline Approved
- Design Plan Issued
- Design Requirements Issued
- Technical Specifications Issued
- Design Release Plan Issued
- Design Resources and Schedule forecast refined for the remainder of the project.

(b) Station Operations Work Control

Refer to N-PROC-MA-0013 and N-PROC-MA-0022 for details regarding milestone requirements.

(c) Project Schedule Milestones may include:

- BOE – Basis of Estimate Approved
- BQA – Budget Quote Acquired for Contract Strategy
- RMP – Risk Management Plan Approved
- CMP – Contract Management Plan Approved by Contract Owner
- SCI – Services Contract N-FORM-10029 Approved
- BID – Contract Bids Received, Evaluated by Supply Chain
- IAE – Engineering Interface Agreement Approved
- DCA – Design Contracts Awarded, PO Approved in PASSPORT
- LLT - Long lead time material contracts identified

- DES -- Preliminary Design Completed
- PEP – Project Execution Plan Approved by Sponsor
- PTI - Work order tasks identified in PASSPORT (assessments complete)
- FRF/FR1 - Full Release Funding BCS approved by OAR.

1.7.4 Execution Phase - Detailed Engineering and Pre-Installation

The main purpose of this phase is for the completion of the detailed design/engineering and preparation for the installation and execution of the modification. The DTL should ensure the Design Engineering Changes are completed and successfully approved by Site Authorities.

Project Manager should ensure Design Engineering deliverables are successfully transferred to the next set of applicable groups for implementation (e.g., Field Engineering, Supply Chain, Work Control).

1.7.4.1 Portfolio Funded Projects

Project Manager should monitor and facilitate the progress of the PM activities described below that are delivered from other organizations.

1.7.4.2 Major Interfaces and Handoffs in the Execution Phase - Detailed Engineering and Pre-Installation

(a) Prior to construction, Project Manager should perform the following:

(1) Describe the prerequisite work required to define the materials, system designs, required qualifications, proceduralization of engineering requirements, and resourcing of activities.

(2) Describe the prerequisite work required to issue approved drawings, construction specifications, installation procedures, work instructions, document manufacturer QA program compliance, non-conformances program compliance, and release of items for installation.

(b) When ECC is governed by N-PROC-MP-0090, the Project Manager should ensure the Engineering Specification (N-TMP-10019) Sections of design requirements and test requirements are forwarded as construction and installation prerequisite work to Field Engineering (Installation) for the development of the Quality Surveillance Plan in accordance with N-PROC-AS-0069, Field Engineering Installation Quality Process and N-PROC-AS-0074, Contractor Quality Surveillance.

(c) For work performed under the Contractor's QA Program, Field Engineering Quality Surveillance Staff (QSS) should review and if acceptable, approve the contractor's Detailed Work Instructions (DWIs) and ITPs.

(d) For work performed under OPG's QA Program, Field Engineering should create the Comprehensive Work Packages (CWP) or Fabrication and Installation Package Release (FIPR) and ITP(s), while the Project Manager issues the DWI(s).

(e) For the development of commissioning plans, MTL should coordinate efforts with the Contract Administrator, FLM Construction, and the Field Engineering (Commissioning), so the task assessments for commissioning are aligned with the project schedule.

(f) Field Engineering should submit the project work instructions to Work Control for implementation.

(g) For projects managed by Site Work Control, the Project Manager should ensure the following activities specifying the construction and installation work packages are progressed towards completion prior to Outage at PO-1, or T-4 to T-3 for the Work Week.

(1) Work protection requests submitted.

(2) Work permits prepared and checked.

(h) Field Engineering (Installation), Contractor's Supervisor and Contract Administrator should review the schedule with the System Window Coordinator or Work Week Leader, and walk down the work areas to ensure readiness.

(i) FLMs of the work group(s) performing the installation should perform the following:

(1) Walk the job sites.

(2) Assign the work.

(3) Prepare the Radiation Exposure Permits.

(4) Sign on to the work permits.

(5) Perform pre-job briefings.

(j) Field Engineering and Work Order Task Planner should assist in the identification of materials to be delivered for the installation of the project.

(k) Contract Administrator and the Contractor's Supervisor should confirm with the Contract Owner the material required for the project installation has been staged at the job site.

(l) Project Manager should oversee the development of the Maintenance Strategy that supports the maintenance of the new SSC to the level of expected dependability in accordance with N-GUID-00120-10001.

(1) Review the DTL's spare parts list of Catalog IDs (CATIDs) and the repair and replace strategy.

(2) Ensure the Maintenance Strategy is approved in accordance with N-GUID-00120-10001 prior to the AFS meeting.

(3) Review with local Finance the incorporation of the Maintenance Strategy costs to the accepting organization's future budgets.

1.7.4.3 Milestones Achieved in Execution Phase - Detailed Engineering and Pre-Installation

Project Manager should monitor and facilitate the progress of the PM activities that are delivered from other organizations in accordance with the milestones described below.

(a) Design Engineering – Detailed Design Engineering

(1) All Engineering Change documentation has been authorized so the material and spare parts can be ordered.

(2) Design Engineering Changes are approved in PASSPORT.

(3) Design Resources and Schedule forecast further refined for the remainder of the project.

(b) Station Operations Work Control Milestones

Refer to N-PROC-MA-0013 and N-PROC-MA-0022.

(c) Project Schedule Milestones may include:

- LLA Long Lead Time Material Contracts Awarded
- ECP All Design Documents Approved and Issued
- ICA Installation Labour Contracts Awarded
- WPI Work Plans Issued
- PTA CWPs, ITPs, FIPRs, prepared. PassPort WO Tasks set to READY
- MED Material and Equipment staged at the job site
- SOP Start of on–site prefabrication (Key Milestone).

1.7.5 Execution Phase – Installation, Commissioning and Turnover

The purpose of this phase is to install, commission affected SSC(s), and document the turnover of the newly installed asset to the accepting organization. If the project is multi-unit or phase then it would apply only to the applicable unit.

1.7.5.1 Major Interfaces and Handoffs in Execution Phase - Installation and Commissioning

Project Manager should monitor and facilitate the progress of the PM activities described below that are delivered from other organizations.

Note: The following guidance does not apply to EPC projects.

(a) Physical Installation of the Project

(1) FLM Construction, Field Engineering (Installation), Contract Monitor, and Contract Administrator should provide oversight to the installation of the project, in accordance with the schedules, Work Plans, DWIs, FIPRs, CWPs, and contract documents. The Contract Administrator should process any approved Contract changes.

(2) Project Manager should confirm the completion of the inspection and testing of the construction and installation activities.

(3) The Owner's Representative (i.e., Field Engineering [Installation] for P&M, Operations FLM for NWMD) and Contract Monitor should close out the project inspection and test installation records **prior** to the pre-commissioning walk down.

(4) Project Manager should confirm design engineering acceptance of the turnover documents prior to commissioning.

(5) Field Changes should be documented, and approved in PASSPORT by the appropriate agent of the Site Design Authority.

(b) Commission the Affected System, Structure, and Components of the Project

The Owner's Representative (i.e., Field Engineering [Commissioning] for P&M, Responsible System Engineer for NWMD) should perform the following:

(1) Ensure the test prerequisites have been fulfilled prior to the test, and the test acceptance criteria are understood by those involved.

(2) Provide oversight to ensure the commissioning activities are performed in accordance with the approved commissioning plans and specified tests.

(3) Be present at the "HOLD" and "WITNESS" points as specified in the commissioning instructions when the contractor (or OPG) commissions their part of the modification.

(4) Ensure changes to equipment and component data due to Commissioning activities are recorded, approved by the appropriate authority, and input into the PASSPORT database.

(5) Prepare a Commissioning Report from the results of the commissioning activities which, if acceptable, is accepted by the DTL and approved by the Project Manager.

1.7.5.2 Major Interface and Handoffs for Execution Phase - Turnover

Project Manager should monitor and facilitate the progress of the PM activities described below that are delivered from other organizations.

(a) Project Manager should assemble the Contractor Supervisors, Contract Administrator, and FLM Construction to perform the project walk down of the individual Engineering Changes prior to demobilization of trade resources.

(b) Prior to the AFS Meeting the Commissioning Report is:

(1) Prepared by the MTL.

(2) Accepted by the DTL.

(3) If acceptable, approved by the Project Manager.

(c) Contractor Supervisor should deliver a turnover package (in accordance with contract documents) to the Contract Administrator for review and to the Contract Owner for approval.

(d) When the modification is being used for its intended purpose as described in the BCS, the project can be declared “In-Service”. Documentation to support this declaration can any of the following:

- Partial AFS
- Authorized To Operate (ATO) in accordance with W-FORM-10086
- AFS
- Letter from the Design Authority agreeing the modification is In-Service
- Documented notification from the Project Sponsor canceling the project due to business reasons or decisions.

(e) When specified, the AFS is performed in accordance with BU ECC procedures.

(f) For Capital Projects the Project Manager should prepare FIN-FORM, Report of Equipment In-Service, to financially declare the modification In-Service.

(g) Project Manager should create the Project First Unit Lessons Learned Report for projects over $10M and submit it to the Project Sponsor. See Section 4 for Record Keeping details.

(h) Project Manager should confirm the completion of the following end of phase documents:

- FIN-MAN-CM-004-FORM 4, Contract Final Inspection
- N-TMP-10204, Lessons Learned Report.

1.7.5.3 Post Available For Service meeting requirements

Project Manager should ensure the following are completed after the AFS meeting in accordance with BU ECC procedures.

(a) Action Tracking assignments have been successfully dispositioned.

Note: All Open Items should be completed within 6 months of the AFS meeting.

(b) Configuration Management exists between the:

- Paper Plant
- Physical Plant
- The analyzed state described in the terms and conditions of the Site's Operating License from the CNSC.

1.7.5.4 Milestones achieved in the Execution Phase - Installation, Commissioning, and Turnover

Project Manager should monitor and facilitate the progress of the PM activities that are delivered from other organizations in accordance with the milestones described below.

(a) Station Operations Work Control Milestones

Refer to N-PROC-MA-0013 and N-PROC-MA-0022 regarding milestone requirements.

(b) Project Schedule Milestones

- SOI – Start of Installation
- CMS – Commissioning Start
- INS – In Service Declaration Completed

  Note: For NWMD this is Authorized To Operate (ATO)

- AFS – Available For Service (Key Milestone).

1.7.5.5 Project Execution – Next Unit: Detailed Planning, Installation, Commissioning, and Turnover

Project Manager should repeat the required previous unit PM steps after the successful disposition of the Action Items from the previous unit(s). The previous units' actual costs and lessons learned are to be applied to the planning and execution of the next unit.

1.7.5.6 Completion Assurance

Project Manager should ensure the design, purchasing, construction, installation, and commissioning activities are complete, and is able to demonstrate the project is safe for the intended use. This should include the following principles:

(a) Identification of the individual SSC critical characteristics applicable to the activity in accordance with the Engineering Specifications.

(b) Review of the objective evidence to demonstrate the ability of all the SSC to work together as intended.

(c) Identification of any outstanding items, and confirmation those outstanding items do not compromise the intended use.

1.7.6 Close Out Phase

Project Manager should complete the following:

(a) Ensure the project expectations were accomplished, with any post AFS actions, technical and financial tasks completed.

(b) Ensure all outstanding OPEN items should be completed and closed no later than 6 months after the AFS meeting. CNE approval is required to go past 6 months.

(c) Ensure the completion of the Project Close Out Lessons Learned, and Finance Close Out Reports.

(d) Ensure the closed out files are forwarded to the appropriate Records department. The following reports to be completed prior to close out:

- FIN-FORM-PA-004
- FIN-FORM-PA-005, Project Closure Report
- N-TMP-10204
- N-TMP-10209, Available For Service Report
- Other closure forms in accordance with the Contractor Management Process Manual.

(e) Ensure the Project Schedule Milestones have been completed.

- DCO – Engineering Close Out Completed
- PCO – Project Financial Close Out
- MOE - “Ministry of the Environment Commitment Complete”, (if applicable)

- MOL - “Ministry of Labour Commitment Complete”, (if applicable)
- RGM - “CNSC Management Commitment Complete”, (if applicable)
- RGC - “CNSC Regulatory Commitment Complete”, (if applicable)
- PCM - “Plan Complete Milestone”.

Note: Refer to Section 4 for Record Keeping details.

1.7.7 Post Implementation Review

Project Sponsor should assemble a PIR Team to perform the PIR in accordance with the PIR Plan described in the BCS. For details refer to OPG-PROC-0056, Post Implementation Review, and FIN-TMP-PA-002, Post Implementation Review Simplified Template. Refer to Section 4 for Record Keeping details.

1.8 Project Controls

Project Controls are used to monitor and evaluate project performance against the baseline. This information is used plan, regulate progress, forecast outcomes and to report the project results to the Project Sponsor and project executive stakeholders.

Project Manager should, with support from PMO, perform the following:

(a) Monitor life cycle, funding release, and annual project performance against initial release gate approved BCS's and current approved baseline and commitments.

(b) Develop and use a project schedule to monitor and report on:

(1) Work completed.

(2) Forecast completion of scheduled activities.

(3) Forecast annual cash flows (expenditures).

(4) Cost and schedule variance against the baseline using available systems.

(c) Regularly monitor Project Scope development within the boundaries approved in the Definition and Authorization Packages.

(d) Report in a timely manner any material changes to the approving OAR authority and Project Sponsor.

(e) Monitor the number of completed Milestones as part of a fiscal year's metrics.

(f) Establish milestones through the authorizing package (e.g. BCS) for approval to the BU Decision Committee in accordance with the following principles:

(1) Milestones identify the Project Manager's commitment to the completion of the modification.

(2) Milestones require resource commitments from the various groups supporting the project schedule.

(3) Acquire resource commitments needed to support the work.

(g) Manage projects through divisional databases in order to communicate project status.

(h) Provide regular updates on project performance indicators.

(i) Monitor project contracts, in accordance with the BCS and PEP deliverables, and control any changes.

- Non-conformances are identified and remedied
- Root causes are dispositioned and corrected.

1.8.1 Project Monitoring and Control Tools

Project Manager should use the various project monitoring and control tools which are typically used throughout the project life cycle to project close out. As an overview, the typical tools used are described below:

(a) ONCORE

Oncore is the Contractor Management system that helps Project and Cost Control Managers keep track of contractor costs such as labour, equipment, and materials, and provides them with information to assess the performance of the contractor. For details see N-INS-00150-10001, Contract Administration in ONCORE.

(b) ProSight

ProSight database incorporates the forecast spending of the individual projects within the Portfolio, and the actual costs as accumulated by the financial accounting database. ProSight also gives the user an overview of total Portfolio commitments and actual costs. Contact Finance Nuclear Investment Management staff for further details.

(c) Proliance

Proliance is a data repository of individual project budgets and actual costs. It is detailed to the work event level of the schedule with the actual costs drawn from the financial databases. Both the schedule and cost events have forecast capability. Contact the P&M PMO for further details.

1.8.2 Project Control Metrics

Project Control metrics are used to monitor the project performance in order to indentify or anticipate areas of the project that may not be progressing as planned. The Project Manager should, with PMO support, monitor and control the following metrics on project life cycle, project release, and annual basis as applicable:

(a) Earned Value Management performance baseline metrics such as,

(1) Cost Performance Index (CPI) which is calculated as:

BCWP (Budgeted Cost of Work Performed)
ACWP (Actual Cost of Work Performed)

(2) Schedule Performance Index (SPI) which is calculated as,

$$\frac{\text{BCWP (Budgeted Cost of Work Performed)}}{\text{BCWS (Budgeted Cost of Work Scheduled)}}$$

(b) Milestone schedule compliance for key deliverables.

(c) Variance Analysis.

(d) Forecast of Project Completion and annual cash flow.

(e) Issues that need management attention.

(f) Project Risk Register.

(g) Work completed this period.

(h) Work expected to be completed in the next period.

(i) Summary of Changes Approved in this period.

1.8.3 Vendor Scorecards

Vendor performance scorecards are used to document the performance of major project vendors (e.g. design agencies, equipment vendors and trades contractors), in accordance with OPG instruction OPG-INS-08173-0001, Supplier Performance Monitoring and Scorecarding.

1.8.4 Programmatic Metrics

Project Manager should monitor and report to the PMO Manager the following Programmatic Metrics as applicable.

- Annual Cost Growth changes
- In-Service Milestones completed
- Oversight Reports and Trends
- Self Assessments, Station Condition Records (SCRs), Lesson Learned Reports

1.9 Project Change Control

Each project is unique and complex in its own way, and changing circumstances during the Project Life Cycle may impact on the project's scope, cost and schedule.

Project Manager should perform the following:

(a) Identify to the Project Sponsor and to the approving OAR authority any significant issues impacting the project.

(b) Monitor their projects for impacts that affect a project, and if the Project Manager determines that a change to the project is required, the Project Manager should initiate a change using one of the change mechanisms. This is illustrated in Appendix B: Project Change Management Process.

(c) Preserve previous actual project performance as change control should not change prior project performance.

Each project change type may require a different approval process due to the criticality of the change, as well as the authority required as mandated by Finance and Project Management governance. If the project change involves many project change types, administer the change via the process requiring the highest authority.

Example: an event occurs which results in a project scope change. This change involves a change to the total release amount, a change in the BCS milestones, and a change to the annual cash flow. A Superseding BCS is prepared and approved but an additional PCRAF is not required to change the milestones and cash flows since a Superseding BCS has a higher authority then a PCRAF and provides approval for all the changes necessary.

1.9.1 Potential Project Changes and Required Action:

(a) Planned Funding Release: Progression of the project through the next approving OAR authority *Decision Gate*.

ACTION: Project Manager creates a BCS and submits it to the applicable BU Decision committee and OAR Authority for approval. Once approved, project performance **going forward** shall be measured against the new commitments.

(b) Change in Scope: A significant change to project scope is required.

ACTION: Project Manager creates a Superseding BCS or OPG-FORM-0077, Project Over-Variance Approval, and submits it to the OAR Authority for approval. Once approved, project performance **going forward** shall be measured against new commitments.

(c) Change In Total Release Amount: Significant change to the amount of money required due to the impact on the project of:

(1) A risk event that was not previously identified and planned for:

ACTION: Project Manager creates a Superseding BCS or OPG-FORM-0077 and submits it to the OAR Authority for approval. Once approved, project performance going forward should be measured against new commitments.

(2) A risk event that was previously identified but without sufficient contingency remaining:

ACTION: Project Manager creates a Superseding BCS or OPG-FORM-0077 and submits it to the OAR Authority for approval. Once approved, project performance going forward should be measured against new commitments.

(3) A risk event that was previously identified and there is sufficient contingency available:

ACTION: Project Manager uses N-FORM-10607 (PCRAF) and submits it to the applicable BU Decision Committee or chair. Once approved, project performance going forward should be measured against new commitments approved in the PCRAF.

(d) Change to Business Case Summary Commitment Milestones and/or Available for Service Milestone:

ACTION: Project Manager submits N-FORM-10607 (PCRAF). If no cash flow changes, Project Sponsor approval is required. If cash flow changes are required refer to (e) below. If the Project Sponsor deems change to be a *Directed Change* then project performance going forward shall be measured against new commitments approved in the PCRAF.

(e) Change in Annual Cash flow: Change to the project's annual cash flow within the bounds of the latest BCS.

ACTION: Project Manager creates a PCRAF which follows approval process outlined in Section 1.9.2.3. If the Project Sponsor deems change is a *Directed Change* then project performance going forward shall be measured against new commitments outlined in the PCRAF.

(f) Change in Key Milestone / Other Milestone Change (not Business Case Summary) Milestone):

ACTION: Project Manager creates a Baseline Change Control Form found in the P&M FEP website. If approved by the *Authorizing Authority of the executing organization*, than the project performance going forward should be measured against new commitments.

(g) Change in Schedule Activity Details or Logic;

ACTION: Project Manager documents in a Baseline Change Control Form

1.9.2 N-FORM-10607, Project Change Request Authorization (PCRAF)

1.9.2.1 Project Change Request Authorization (PCRAF) Principles

Project Manager should document changes to BCS cash flows or AFS/BCS milestones with the PCRAF in accordance with the following principles.

(a) PCRAF can only document changes within the approved release limits originally defined in the BCS. The trigger for documenting the cash flow change is when the Project Manager has determined a definite variance will occur.

(b) A PCRAF shall only change current project commitments (i.e., schedule activities and budget) directly impacted by the PCRAF. Schedule activity changes should be referenced with the PCRAF number within the schedule. The history of any completed schedule activities shall not be changed unless they are directly related to the PCRAF.

(c) An approved PCRAF shall only make changes to the *Project Baseline Schedule* and/or the Control Budget. A PCRAF cannot change the Original Budget, or the *Primary Approved Baseline Schedule* as described in the latest approved BCS.

1.9.2.2 Project Change Request Authorization (PCRAF) Change Type

Project Manager should select the affected PCRAF Change Type in accordance with the following principles:

(a) Change to the amounts of BCS cash flows and corresponding schedule change within the bounds of the original annual cash flows without Contingency.

Note: If the cash flow is changing due to a minor scope change, N-FORM-11170 should to be included with the PCRAF.

If the scope increase is material in accordance with guidance from Nuclear Finance – Investment Management, the change in scope should be authorized by a Superseding BCS or OPG-FORM-0077 and approved by the applicable OAR.

(b) Project Contingency Request within Release Amounts with Contingency.

(c) Delays to AFS or other BCS Milestones.

(d) *Directed Change.*

1.9.2.3 Project Change Request Authorization (PCRAF) Routing for Approval

Project Manager should prepare the PCRAF and route it for approval in a timely manner and in accordance with the following steps:

(a) Project Manager's Stratum V Director shall review and if acceptable sign to indicate concurrence.

(b) Project Sponsor should review, and if acceptable sign to indicate concurrence. If PCRAF is for BCS milestone changes only [i.e., no annual cash flow changes, refer to 1.9.1 (d)], then go to (i) below.

(c) BU Finance representative should confirm the current cash flow and changes are within the approved amounts prior to the progression of the PCRAF for the applicable BU Reviewer or Decision Committee.

(d) Finance Director from the BU should present to the BU Decision Committee/Chair a summary of the PCRAFs that have proceeded through the previous steps and are recommended for review.

(e) BU Decision Committee/Chair should ensure the Portfolio 'Released' and 'Balance to be Released' cash flows remain balanced at the fleet level throughout current year and future years.

(f) If acceptable, the BU Decision Committee Chair or delegate should sign the PCRAF as approved.

Note: PCRAFs to withdraw contingency for projects in which P&M controls and manages the contingency require P&M VP approval but not BU Decision Committee approval (e.g., AISC or PISC).

(g) Project Manager should distribute copies of the approved PCRAF to the following:

- PMO (P&M only)
- Finance - Nuclear Investment Management
- The associated Financial Controller (if applicable)
- See Section 4 for Record Keeping details.

(h) Finance - Nuclear Investment Management should update the project Control Budget.

(i) Project Manager should ensure the project schedule is updated appropriately.

1.9.3 N-FORM-11044, Transfer of Portfolio Responsibility

(a) Project Manager of the original executing organization may transfer its project responsibility to another group by preparing N-FORM-11044, Transfer of Portfolio Responsibility.

(b) Stratum IV Department Manager transferring the project and the Stratum IV Department Manager receiving the project should jointly approve N-FORM-11044.

Note: For transfers that are complex in nature, further details of explanation are attached to the N-FORM-11044.

(c) Project Manager of receiving organization should forward a copy of the approved N-FORM-11044 to Nuclear Finance Investment Management.

(d) Nuclear Finance Investment Management should update the financial source systems to ensure costs are directed to the new executing organization.

1.9.4 N-FORM-11170, Project Scope Control Authorization

Project Manager should document any project scope growth by completing N-FORM-11170 and associated Impact Checklist.

This should occur even if the scope change may be accommodated within released cash flows. This check list is a tool that may identify emergent issues not immediately considered at the time of scope approval.

The approved original is filed in the PM File. Refer to Section 4 for Record Keeping details.

2.0 ROLES AND ACCOUNTABILITIES

Refer to N-PROG-AS-0007

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Authorizing Authority of the executing organization is a position holder within OPG. This individual retains the authority to bind the corporation regarding PM decisions. It can vary in Stratum level or title (i.e., Director or Vice President).

Business Driver is a Business Unit's ability to meet Business Plan Objectives. Examples would be influences on Safety, Reliability, Human Performance, Value (decrease costs, increase revenue).

Decision Gate is a management hold point in the Project Life Cycle where decisions and approvals are required.

Directed Change is a project change resulting from event(s) outside the project's influence. *Directed Changes* are not a result of poor-planning. If a *Directed Change* is initiated, project performance going forward shall be measured against the new commitments. If a change is not a *Directed Change*, then project performance will continue to be measured against the previously approved commitments.

The following are examples of events which may result in a *Directed Change*:

(a) Major unforeseen station changes to outage or on-line plans and priorities (e.g. changes to outage dates, conflict with work on priority systems)

(b) Major unforeseen variations in site conditions (e.g. underground boulders, soil contamination, water level) provided that a reasonable and prudent effort was taken to survey site conditions.

(c) New and emergent requirements imposed by regulatory authorities (e.g. CNSC, TSSA, Ministry of Labour, Ministry of Environment) provided that a reasonable and prudent effort was taken to anticipate these new requirements (i.e., engineering code changes are usually communicated to practitioners ahead of time before the codes are enforced).

(d) Changes to project priorities or funding availability imposed by Portfolio Managers (including Business Planning by Finance) and AISC or PISC.

Nuclear Refurbishment (NR) Project Bundle refers to the major scope sub-projects that the NR overall program is divided into. A NR Bundle is typically further divided into smaller sub-project groups or individual projects.

Paper Plant is the collection of flow diagrams, engineering drawings and technical specifications that describe the SSC of the assets in Nuclear. This collection of information is analyzed to see how all the pieces safely interact with each other for the generation of electricity in Nuclear. It is the basis of the Regulatory license that allows OPG Nuclear to operate, maintain, and modify those assets.

Physical Plant - consists of the SSC that make up the assets in Nuclear.

Primary Approved Baseline Schedule consists of the schedule activities and logic described in the latest approved BCS from the last *Decision Gate*. A new *Primary Approved Baseline Schedule* is created when the approving OAR authority approves the next BCS required for the next project phase. For example, a Partial Release BCS ends, and a Full Release BCS is approved.

Project Baseline Schedule consists of the schedule activities and logic described in the latest approved PCRAF(s), and/or Superseding BCS within the duration of the same project phase. The *Project Baseline Schedule* incorporates the schedule impacts from approved changes between BCS approved, project phase *Decision Gates*.

3.2 Abbreviations and Acronyms

ACWP	Actual Cost of Work Performed
AFS	Available For Service
AISC	Asset Investment Screening Committee
ASL	Approved Suppliers List
ATO	Authorized to Operate
BCS	Business Case Summary
BCWP	Budgeted Cost of Work Performed
BCWS	Budgeted Cost of Work Scheduled
BOE	Basis of Estimate
BOM	Bill of Material
BU	Business Unit
BU VP	Business Unit Vice President
CAT ID	Catalog Identification in PassPort
CEO	Chief Executive Officer
CMFA	Constructed Minor Fixed Assets
CMO	Contract Management Office
CNE	Chief Nuclear Engineer
CNO	Chief Nuclear Officer
CPI	Cost Performance Index
CWP	Comprehensive Work Packages
DAIA	Design Authority Interface Agreement
DTL	Design Team Leader
DWI	Detailed Work Instruction
ECC	Engineering Change Control
ES MSA	Extended Services Master Services Agreement
EPC	Engineer, Procure, Construct
FAC	Financial Account Classification
FEP	Front End Planning
FIPR	Fabrication and Installation Package Release
FLM	First Line Manager
GRB	Gate Review Board
IM&CS	Inspection Maintenance and Commercial Services
INS	In Service Declaration
ITP	Inspection and Test Plan
MTL	Modification Team Leader
NR	Nuclear Refurbishment
NWMD	Nuclear Waste Management Division
OAR	Organizational Authority Register
OEB	Ontario Energy Board
OM&A	Operating, Maintenance and Administration
OPEX	Operating Experience
OPG	Ontario Power Generation
P&M	Projects and Modifications
PAC	Project Approval Committee
PCRAF	Project Change Request Authorization Form
PDRI	Project Definition Rating Index
PEP	Project Execution Plan
PIR	Post-Implementation Review

PM	Project Management
PMO	Project Management Office
PO	Purchase Order
PISC	Project Investment Screening Committee
PV_{Alt}	Present Value
QA	Quality Assurance
QSS	Quality Surveillance Staff
REGC	Regulatory Commitment
RFP	Request for Proposal
RFQ	Request for Quotation
RMP	Risk Management Plan
RRA	Records Retention Authorization
SC	Screening Committee
SCR	Station Condition Record
SOW	Statement of Work
SPI	Schedule Performance Index
SPOC	Single Point of Contact
TCD	Target Completion Date
PSRB	Program Scope Review Board (NR)
SSC	Systems, Structures and Components
VE VP NWMD	Value Engineering Vice President, Nuclear Waste Management Division

4.0 RECORDS AND REFERENCES

4.1 Records

4.1.1 The Project Manager is responsible for the record keeping of project documents.

4.1.2 There are two methods of Records Keeping for the controlled documents or records produced as a result of this procedure, and they are as follows:

(a) The Project Management (PM) File which is further described in the Records Retention Code (RRC) N02-0038. This RRC is:

(1) Managed in accordance with N-PROC-AS-0003, Controlled Document Management and N-PROC-AS-0042, Records and Document Management.

(2) Described in accordance with the first chart at the end of this section.

Note: Since the RRC has evolved over time, the Stratum III Project Manager is allowed to add disposition notes to the file that clarify discrepancies.

(b) The project working files are kept locally with the associated project management department, and are described in the second chart of this section. These records are retained for two years after the approval of the Project Closure Report, FIN-FORM-PA-005, and then destroyed.

4.1.3 Project Controlled Documents are associated with each other in PASSPORT by the Project Identification Number which is supplied by local Finance, and should be included with any filing submissions.

4.1.4 There are two types of Project Controlled Documents and Records;

(a) Those that record the impact of the modification on the Plant Design Bases, are governed by BU ECC procedures. Typically, these records and documents are described as QA Records, which in this situation is a Records classification.

(b) Those that describe the project management and BU Decision Committee business processes are governed by this procedure. These records and documents are classified as non-QA Records, and are filed in the PM File or project working file.

4.1.5 Within the PM File is the BCS which is an essential non-QA OPG Confidential Record which can be released to the Ontario Energy Board (OEB) during the rate setting hearings. Since the BCS can contain proprietary information such as estimates, contingency, vendor information, etc., the BCS should be managed differently than other records and documents in the PM File. That is,

(a) The BCS is indexed but not linked electronically in PASSPORT, so it cannot be viewed by unauthorized personnel.

(b) If requested by the OEB where it can be released into the public domain, the BCS should first be reviewed by Nuclear Finance. The sensitive information should be redacted with a heavy black marker prior to release in accordance with OPG-STD-0030, Classification, Protection and Release of Information.

(c) When Records staff receives a request to view or copy a BCS filed in the PM File, they should first receive permission from the Project Manager or PMO Manager prior to releasing the BCS to OPG personnel who are not listed on the BCS signature page. The original BCS should not leave the Site Secure Storage area.

Note: P&M Vice President has delegated the authority to these managers in accordance with OPG-STD-0030.

(d) PM File

Record Created	Associated Form Number	QA Record? Y/N	Filing Information/Retention (PASSPORT Type/Sub-Type)
Site PM File		N	Site PM File, filed by Project ID number. Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. Records Retention Code (RRC): N02-0038.

Record Created	Associated Form Number	QA Record? Y/N	Filing Information/Retention (PASSPORT Type/Sub-Type)
Project Charter	N-TMP-10117	N	Issued in Passport as Controlled Document Doc Type = PLAN Sub Type = PCH Doc No. N or P or, D-PCH--SCIXX-XXXXX Filed in site PM File. Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. RRC: N02-0038.
Type 1 Business Case Summary	OPG-FORM-0074	N	Indexed in Passport as Controlled Document Doc Type = PLAN Sub Type = BCS Doc No. N or P or, D-BCS-SCIXX-XXXXX Filed in site PM File, not linked in PassPort. Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. RRC: N02-0038.
Type 2 Business Case Summary	OPG-FORM-0075	N	Per OPG-FORM-0074 above.
Type 3 Business Case Summary	OPG-FORM-0076	N	Per OPG-FORM-0074 above.
Project Over-Variance Approval	OPG-FORM-0077	N	Per OPG-FORM-0074 above.
Project Execution Plan (without FEP process)	N-TMP-10119	N	Issued in Passport as Controlled Document Doc Type = PLAN Sub Type = PEP Doc No. N or P or, D-PEP-SCIXX-XXXXX Filed in site PM File. Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. RRC: N02-0038.
Project Execution Plan Form (with FEP process)	N-FORM-11172	N	Filed in site PM File as a Record.
Transfer of Portfolio Responsibility	N-FORM-11044	N	Filed in site PM File.

Record Created	Associated Form Number	QA Record? Y/N	Filing Information/Retention (PASSPORT Type/Sub-Type)
Lessons Learned Report	N-TMP-10204	N	Issued in Passport as Controlled Document Doc Type = REP Sub Type = LLD Doc No. N or P or, D-LLD-SCIXX-XXXXX Filed in site PM File. Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. RRC: N02-0038.
Report of Equipment In-Service (Capital Projects only)	FIN-FORM-PA-004	N	Filed in site PM File.
Project Closure Report	FIN-FORM-PA-005	N	Copy filed in PM File
Disposition Note	n/a	N	Filed in site PM File
Post Implementation Review (Simplified Template)	FIN-TMP-PA-002	N	Issued in Passport as Controlled Document Doc Type = REP Sub Type = PIR Doc No. N or P or, D-PIR-SCIXX-XXXXX Filed in site PM File Retention = 6 Years after project closed per the approval of Project Closure Report, FIN-FORM-PA-005. RRC: N02-0038.

(e) Project Working File

Record Created	Associated Form Number	QA Record? Y/N	Filing Information/Retention (PASSPORT Type/Sub-Type)
Project working file		N/A	Stored locally in the project management department. Destroy 2 years after close of project, i.e., clock starts after FIN-FORM-PA-005 approval.
AISC Part A: Issue Characterization	N-FORM-10765	N	Filed departmentally. Destroy 2 years after the close of the project.
Cost Estimate & Request for Conceptual Funding	N-FORM-10945	N	Filed departmentally. Destroy 2 years after the close of the project.
AISC Part B: Decision Record	N-FORM-10994	N	Filed departmentally. Destroy 2 years after the close of the project
Project Change Request Authorization (PCRAF)	N-FORM-10607	N	Filed departmentally. Destroy 2 years after the close of the project.
Project Scope Control Authorization	N-FORM-11170	N	Filed departmentally. Destroy 2 years after the close of the project.
Project Authorization Package (if applicable)	N-FORM-11466	N	Filed departmentally. Destroy 2 years after the close of the project.
NWMD Needs Statement (NWMD only)	N-FORM-11491	N	Filed departmentally. Destroy 2 years after the close of the project.

4.2 References

4.2.1 Performance References

- FIN-FORM-PA-004, Report of Equipment In-Service
- FIN-FORM-PA-005, Project Closure Report
- FIN-TMP-PA-002, Post Implementation Review Simplified Template
- I-PROC-MP-0001, Engineered Tooling Modification Process
- N-CHAR-AS-0002, Nuclear Management System
- N-FORM-10607, Project Change Request Authorization Form (PCRAF)
- N-FORM-10765, AISC Part A: Issue Characterization
- N-FORM-10945, Cost Estimate and Request for Conceptual Funding
- N-FORM-10958, Modification Outline
- N-FORM-10959, Design Scoping Checklist
- N-FORM-10994, AISC Part B: Decision Record
- N-FORM-11044, Transfer of Portfolio Responsibility
- N-FORM-11170, Project Scope Control Authorization
- N-FORM-11172, Project Execution Plan Form
- N-FORM-11252, Nuclear Refurbishment Change Control Form
- N-FORM-11392, Funding Request Form
- N-FORM-11454, OBU Funding Request
- N-FORM-11466, Project Authorization Package (PAP)
- N-FORM-11491, NWMD Needs Statement
- N-GUID-00120-10001, Nuclear Integrated Supply Planning
- N-GUID-09701-10014-R000, NR - Transfer of Work Process
- N-INS-00100-10000, Project Cost Estimating Instruction
- N-INS-00120-10014, Project Risk Management
- N-INS-00120-10019, Value Engineering
- N-INS-00120-10022, NR - Cost and Schedule Change Control
- N-INS-00150-10001, Contract Administration in ONCORE
- N-INS-06931-10001, On-Line Cycle Planning Process
- N-INS-09701-10005, Nuclear Project - Gated Process
- N-PLAN-08115-10000, Nuclear Operations Project Portfolio Business Plan
- N-PROC-AS-0069, Field Engineering Installation Quality Process

- N-PROC-AS-0074, Contractor Quality Surveillance
- N-PROC-HR-0018, Resolution of Differing Professional Opinions
- N-PROC-LE-0010, Nuclear Refurbishment - Cost and Schedule Change Control
- N-PROC-LE-0013, Nuclear Refurbishment - Contingency Development And Management
- N-PROC-MA-0013, Planned Outage Management
- N-PROC-MA-0022, Integrated On-Line Work Scheduling
- N-PROC-MP-0090, Modification Process
- N-PROG-AS-0007, Project Management
- N-PROG-RA-0003, Corrective Action
- N-QG-403-00023, Nuclear Project Staff Qualification Guide
- N-TMP-10019, Engineering Specification
- N-TMP-10117, Project Charter
- N-TMP-10119, Project Execution Plan
- N-TMP-10204, Lessons Learned Report
- OPG-FORM-0074, Type 1 Business Case Summary
- OPG-FORM-0075, Type 2 Business Case Summary
- OPG-FORM-0076, Type 3 Business Case Summary
- OPG-FORM-0077, Project Over-Variance Approval
- OPG-INS-08173-0001, Supplier Performance Monitoring and Scorecarding
- OPG-PROC-0058, Procurement Activities
- OPG-STD-0017, Organizational Authorities Register (OAR)
- OPG-STD-0076, Developing and Documenting Business Cases
- W-PLAN-08100-00002 NWMD Project Investment Steering Committee Terms of Reference
- W-TQD-400-00002, Nuclear Waste Management Division Engineering Support Personnel Training and Qualification Description

4.2.2 Developmental References

- FIN-MAN-CM-002, Technical Contractor Management Process Manual
- N-GUID-01920-10000, Guideline for Managing the Design Agency Interface, per N-STD-MP-0009
- N-INS-00700-10004, Facilities Commercial Modification Control
- N-INS-00700-10006, Commercial Modifications on Nuclear Sites
- N-PLAN-08115-10000, Nuclear Operations Project Portfolio Business Plan

- N-PROC-AS-0003, Controlled Document Management
- N-PROC-AS-0042, Quality Assurance Records
- N-PROC-MA-0024, System Performance Monitoring
- N-PROC-MP-0060, Aging Management Process
- N-STD-AS-0020, Nuclear Organization
- N-STD-MP-0009, Contractor\Owner Deliverables And Activities Interface Control
- NK38-INS-09701-10001, Darlington Refurbishment Program – Scope Review Instruction
- OPG-PROC-0005, Materials and Supplies Inventory and Control
- OPG-PROC-0007, Project Accounting and Reporting
- OPG-PROC-0056, Post Implementation Review
- OPG-STD-0030, Classification, Protection, and Release of Information

5.0 REVISION SUMMARY

This is an Intent revision.

- Revision bars have been used.
- Incorporate NWMD and the execution of certain NR projects transferred to P&M under this procedure.
    - Execptions updated to reflect inclusion of NWMD and NR projects
    - Added Section 1.4 regarding projects funded by NR and executed by P&M
    - Performance and Developmental References, Acronyms and Definitions updated.
- References to FAC 22860 were removed in order to align with current Finance processes
- Aligned the procedure with existing processes such as:
    - Financial oversight of Provision Funding by NWMD PISC
    - Changes to BCS process in accordance with OPG-STD-0076
    - Financial oversight of Nuclear Refurbishment Funding by Program Scope Review Board and Gate Review Board
    - Project phase milestones and deliverables updated
    - Project Control metrics expanded

- Revisions to N-FORM-10607 & N-FORM-10945
- New forms N-FORM-11466 & N-FORM-11491
- ES MSA Request for Work
- Revised PCRAF annual cash flow threshold
- Records Retention Codes.

- Added additional detail on project phase *decision gates* including updated figures
- Manager of Finance - Nuclear Investment Management summarizes in N-FORM-10765, AISC Part A, the fleet wide review to determine if an adverse condition or opportunity exists.
- Incorporated dispositioned recommendations from N-PLAN-08115-10000, 2011-2020 Nuclear Operations Project Portfolio Business Plan
- Incorporated dispositioned recommendations from AR 28124311-02 (i.e., resolve procedural gaps between Portfolio and NWMD funded projects)
- Added the Conduct of Project Management Performance Indicators Annual Cost Growth and In-Service Milestones
- Added paragraph regarding expedited projects
- Changed ‘Executive Management Team’ to ‘Enterprise Leadership Team’
- The ambiguous phrase ‘senior management’ was replaced with ‘project executive stakeholders’ who are those Executive Representatives listed in the N-FORM-11172, PEP Section 4.0 Project Organization Map
- Appendices revised
- Performed a grammatical clean up of the document.

Appendix A: Business Unit Project Decision Committees

A.1.0 BUSINESS UNIT DECISION COMMITTEES

BU Decision Committees (e.g., AISC and PISC) are senior cross-functional committees with representation from the BU, Engineering, Nuclear Finance, and P&M. These committees provide a forum to review BSCs and their supporting documents. For details regarding PISC, see W-PLAN-08100-00002 NWMD Project Investment Steering Committee Terms of Reference. The committees may perform the following:

(a) Challenge whether there has been an acceptable range of alternatives considered.

(b) Challenge the feasibility of the proposed solution to the Business Gap or opportunity.

(c) Consider whether the solution has taken advantage of all available OPG Management Systems.

(d) Determine if the solution has identified all internal department resources and has received commitments from the respective departments.

(e) Consider whether there has been an effort to reduce engineering costs.

(f) Recommend approval regarding additions to the Nuclear and Provision Portfolios by reviewing the Rolling Agenda.

(g) Prioritize the investments on a fleet basis.

(h) Approve a recommended schedule for investments.

(i) Determine the overall fleet priority and schedule for proposals.

(j) Recommend improvements to the PM governance and processes.

(k) Seek advice from subject matter experts.

(l) Provide the review of business risk to the fleet and prioritizes the project Nuclear and Provision Portfolios to minimize that risk.

(m) Determine if the BCS provides a strategy to spread implementation costs across the nuclear fleet.

A.2.0 SITE SCREENING COMMITTEE

Sponsored by the BU VP, the Site Screening Committee (SC) receives from OPGN staff issues that have been identified as opportunities for investment or as business gaps between current performance and *business drivers*. The Site SC provides technical dispositions to the Business Gap or opportunity which typically may not be resolved with the available site resources.

A.3.0 SITE PROJECT APPROVAL COMMITTEE

Sponsored by the BU VP, the Site Project Approval Committee (PAC) reviews the scope of the individual projects being executed at their site and considers the cumulative effect to the site's portion of the Portfolio, as well as the fleet view perspective and adherence of the project's cost and schedule to the Business Plan. The Site PAC reviews all submitted PCRAFs, consider their affect on the Portfolio cash flows, and offer their recommendation to the BU VP.

ONTARIO POWER GENERATION

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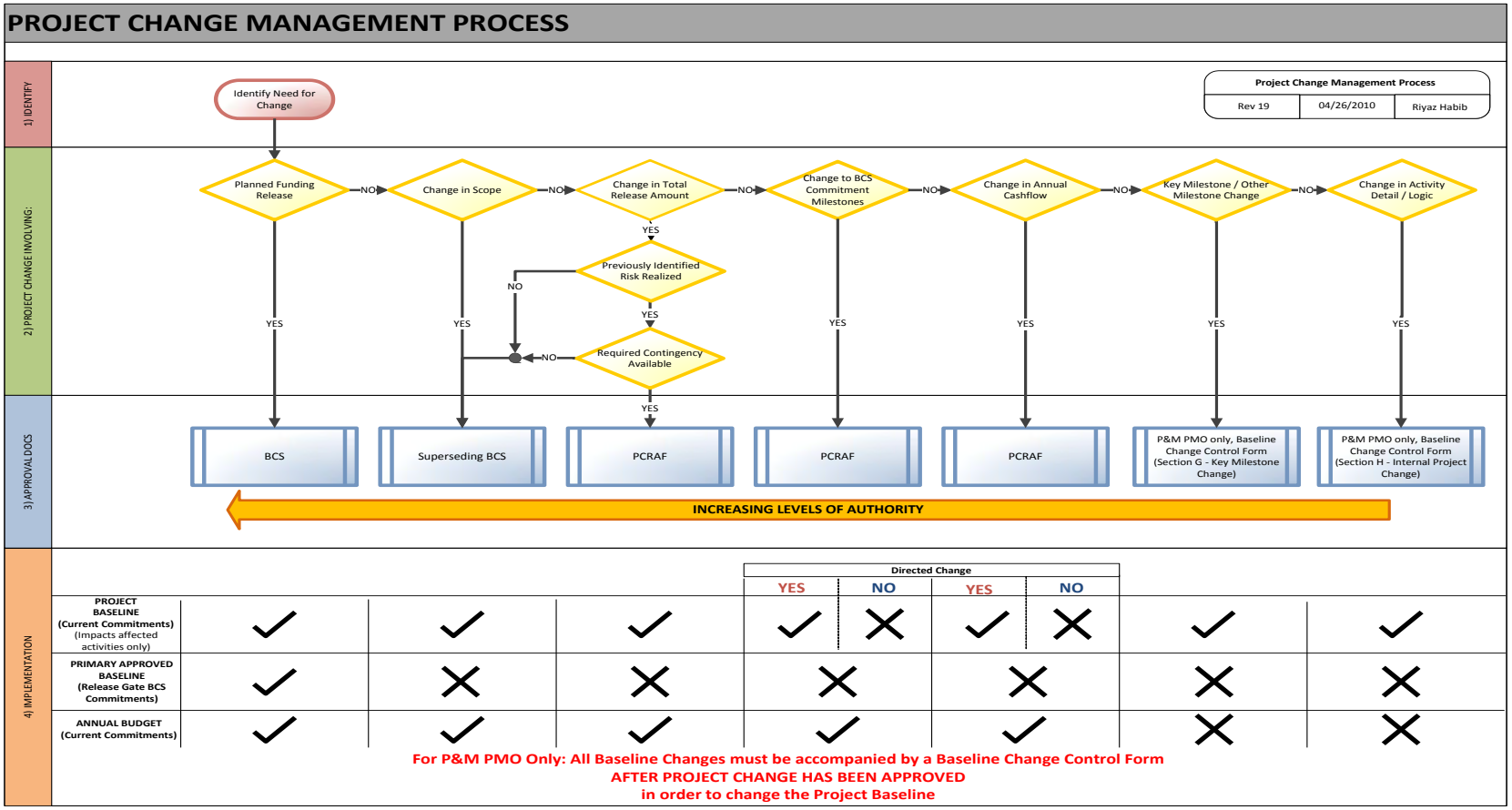
Appendix B: Project Change Management Process



UNDERTAKING J15.5

Undertaking

To review the list of Tier 1 Business Case Summaries referred to at Attachment 1 of L-4.2-AMPCO-17 to determine whether there have been any updates to the Tier 1 Business Case Summaries.

Response

There have been three updates to the Tier 1 Business Case Summaries since November:

(a) 31710 - DN Shutdown Cooling Heat Exchanger Replacement (see Attachment 1 which has confidential content as marked)

(b) 38948 - DN Zebra Mussel Mitigation Improvements (see Attachment 2 which has confidential content as marked)

(c) 80022 - DN OH180 Aging Management Hardware Installation (see Attachment 3 which has confidential content as marked)

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

OPG-FORM-0076-R005*

Type 3 Business Case Summary

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

Executive Summary and Recommendations

Project Information			
Project #:	16-31710	**Document #:**	D-BCS-33410-10003
Project Title:	Darlington Shutdown Cooling Heat Exchanger Replacement		
Class:	☐ OM&A ☒ Capital ☐ Capital Spare ☐ MFA ☐ CMFA ☐ Provision ☐ Others:	**Investment Type:**	Sustaining
Phase:	Execution	**Release:**	Partial
Facility:	Darlington	**Target In-Service or Completion Date:**	2020-Oct-30 (Completion Date)

Project Overview

We recommend the Gate 3B approval to proceed and the release of $ 43,307 k, including [redacted] of contingency.

This brings the total-to-date release to $ 82,136 k, including [redacted] of contingency.

The total project cost is estimated at $ 112,845 k (including [redacted] of contingency). The quality of the estimate for this release is Class 3, and for the total project is Class 3.

Following the first heat exchanger replacement (completed in Q3 2016), the total project estimate has increased over the previous estimate of $ $56,085k (including [redacted] of contingency) due to a number of project risks realized as well as several new discovery items which were not anticipated in the previous release. All items are now included in the total project estimate with the detailed variance included below.

This release will fund the following scope of work:

- **Complete revision of engineering change packages for remaining 7 SDC HX replacements.**
- **Complete non-long lead procurement and execution (installation planning, installation, commissioning, & engineering change control (ECC) close-out) for the 2nd, 3rd, 4th and 5th Shutdown Cooling Heat Exchanger (SDC HX) replacements.**
- **Complete installation planning for the 6th SDC HX replacement.**
- **Complete preparation of Full Execution Release Business Case Summary for the last 3 SDC HX replacements.**

Problem Statement/Business Need:

The baffle supports in all SDC HX's are deteriorated due to microbiologically induced corrosion (MIC). Consequently, the SDC HX tubing is susceptible to damage arising from flow induced vibrations, tube fretting and circumferential cracking. To date, no tubes have leaked*; however, as baffle plate corrosion continues, the risk of a tube leak will increase. A tube leak would result in significantly increased emissions of tritium to the lake, which would be a violation of the environmental and radiation protection requirements of the station Power Reactor Operating License.

***Note:** Following replacement of the first HX (2-33410-HX2) in Q3 of 2016, a partial tube side eddy current inspection was performed on the old HX in December 2016 in order to identify the extent of degradation. Results of the inspection indicate that the degradation of the baffle supports had not resulted in any observable damage to the HX tubing. While this inspection indicates the risk of a tube leak is lower than initially expected, it is not necessarily representative of the condition of the remaining 7 HX's that still require replacement. This is further supported by recent OPEX in January 2017 when tube degradation resulted in a tritium leak on a HX (1-33410-HX2) as identified in SCR D-2017-00195. This recent event supports the urgency to replace the heat exchangers as soon as possible, as the degradation of each heat exchanger and its remaining service life is unpredictable.

Ultrasonic testing (UT) of the SDC HX shells indicate that the shell wall thickness is reduced in locations due to pitting caused by MIC. Based on the currently estimated corrosion rates for the SDC HX's with the greatest amount of corrosion, the minimum allowable shell wall thickness could be reached at isolated pit locations within 3.5 years (from the time of inspection in 2012), resulting in the operation of the Shutdown Cooling system outside of the design basis.
In order to prevent the onset of additional corrosion pits in the shell and baffle supports, the operating procedure has been

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

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Project Overview

revised to enable continuous service water flushing of the SDC HX's during the chlorination season. This improvement will mitigate the onset of MIC in new locations due to stagnant water conditions; however, it will not stop or slow down the corrosion of the SDC HX's at existing pit locations.

A tube or shell side leak would require the SDC HX to be taken out of service, isolated, and repaired, which would be a loss in redundancy of the Shutdown Cooling system and a reduction in system reliability. A tube side leak could also cause a forced shutdown of a reactor unit, resulting in a loss of production and increasing the Unit Forced Loss Rate. Furthermore, for any planned outage, the unavailability of a SDC HX would increase the time for Primary Heat Transport (PHT) system cool down, thereby extending outage duration and further increasing the forced loss rate. The unavailability of a SDC HX would also have a negative impact on Unit Refurbishment flow defueling activities, resulting in an increase in the period of time for flow defuel. This would negatively impact Refurbishment outage critical path and overall duration.

Summary of Preferred Alternative:

In order to address the ongoing corrosion of the Shutdown Cooling Heat Exchangers and the impending end of service life, a complete replacement of all eight (8) SDC HX's is recommended. Replacement of the SDC HX's will be dimensionally compatible with the existing heat exchangers, and almost identical from a thermal and hydraulic performance point of view. There will be no change to the tubing (I-800) or shell material (SA516 GR70), and the material chosen for the internal components (segmental baffle plates, tie rods, etc.) will be changed from carbon steel to stainless steel grade 316L, a material more resistant to MIC. The new SDC HX's will have an increased service life of 40 years, thereby ensuring their availability until the end of station life following refurbishment, approximately 2055.

Each SDC HX will be planned for replacement with the reactor unit at power, and prior to the corresponding reactor unit's planned Refurbishment outage. For specific heat exchangers, this may be not be possible and therefore the heat exchanger will be replaced during the Refurbishment outage or as soon as possible post-Refurbishment in accordance with Darlington Online and Refurbishment work planning processes.

Disposal will be performed by Nuclear Waste Management Division (NWMD).

History of BCS releases and project cost estimates:

The total project cost is now estimated at $[redacted] plus [redacted] k of contingency, compared to [redacted] k, plus $[redacted] k of contingency in the previous release.

The total project cost has increased by $ 56,760 k due to the following:

Two key factors resulted in the increased project cost estimate. The first is an increase in the field execution duration for each HX replacement, and the second is the increase in the engineering cost estimate as a result of additional design analysis activities.

1. Field Execution Duration:

The 1st SDC HX was replaced in Q3 2016 and took approximately 68 days working 24/7 (and 4 weeks each on pre-requisites and post-requisites working 40hrs/week). This was a significant increase from the estimated duration of 30 days and is attributed to the following major factors which either added additional activities to the critical path and/or impeded productivity in the field:

- Installation of temporary piping supports to account for seismic and Condensation Induced Waterhammer (CIWH) loadings during the period of time when the old HX is removed and the new HX has not been fully installed.
- Significant complexities associated with the fit-up and welding of small bore nuclear class stainless steel piping and large bore nuclear class carbon steel piping connections to the new SDC HX.
- The implementation of radiological proteotion measures (set-up and operation of portable air driers, installation of temporary lead shielding blankets, flushing of the HX with demineralised water, set-up and removal of tented areas) to contain and minimize radiological dose fields and radiological dose uptake in the work areas.
- The summer of 2016 was the hottest on record with 38 days when the temperature reached above 30 degrees Celsius. This resulted in ambient temperature and breathing air temperatures in the work areas (inside containment) approaching 40 degrees Celsius. This presented a significant concern for worker heat stress and resulted in work stoppages or reduced field work hours in order to minimize the risk of worker injury.
- This was a first-of-a-kind (FOAK) installation that had many first-in-a-while (FIAW) aspects to it. Several attributes were not fully understood in advance, and led to issues being identified during field execution, which delayed the progression of work while a path forward was obtained.

Based on the experience gained on the first replacement and incorporating lessons learned and expected efficiencies,

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Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003

Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Project Overview

subsequent HX replacements are planned for a 40 day field execution window working 6x20's (and 3 weeks each on pre-requisites and post-requisites working 40hrs/week).

2. Engineering:

Additional engineering modifications and piping stress analysis required the Design Packages to be revised to address legacy design items which were not initially known to the project, specifically Condensation Induced Waterhammer (CIWH) loadings, and non-rigid (flexible) Heat Exchanger Design. In addition, the engineering support required during construction for Field Initiated Changes (FIC's) was significantly underestimated, and the effort to incorporate lessons learned into the engineering packages was originally not included.

This BCS is prepared on the basis that engineering modifications for seismic and CIWH loadings are no longer required for the remaining 7 HX installations, and therefore the engineering, procurement, construction and OPG support costs have been removed and reassigned to contingency.

Key Variances are as follows:

- Estimated OPG resource costs have increased from approximately $10.6 M to $13.9 M. The variance is primarily a result of increased resource requirements to support the 40 day HX replacement duration.
- Estimated ES MSA vendor costs have increased from approximately [redacted] to [redacted]
  - Vendor Design cost has increased from [redacted] to [redacted] as a result of the engineering changes highlighted above.
  - Vendor Procurement cost has increased from [redacted] to [redacted] as a result of increased materials to fabricate temporary piping supports in support of revised Engineering, new piping spool piecies, and an increase in the required tooling and equipment to support construction activities.
  - Vendor Construction cost has increased from [redacted] M to [redacted] M. The variance is is attributed to the increased resources required to support the field duration which increased from 30 to 40 days. In addition, the crew size per shift was significantly underestimated and has been revised to account for approximately 30 trade's individuals per shift.
  - Vendor Project Management cost has increased from [redacted] to [redacted] This is attributed to the increased overall project duration, and the addition of a dedicated Project Manager, Construction Lead, and Modification Team Leader in order to ensure continuity and knowledge transfer of key expertise across all 8 HX replacements.
- Estimated OPG Interest cost has increased from [redacted] to [redacted] The increase is proportionate to the increase in estimated project cost.
- Estimated Contingency cost has increased from $ [redacted] to [redacted] For each remaining HX installation, [redacted] of contingency has been allocated to the risk of designing and installing engineering modifications associated with temporary piping supports for seismic and CIWH loadings. In addition, [redacted] of contingency has been allocated to the risk of each field execution extending beyond the planned 40 day duration as a result of unexpected field conditions or unpreventable delays or reductions in field productivity attributed to station delays, transients or extreme weather conditions.

History of scope and schedule changes:

There have been no scope or schedule changes since the previous BCS.

Key Assumptions and Risks:

It is assumed that all HX's will be replaced with the reactor units online, with the exception of the Unit 2 HX #2, which will be replaced during Unit 2 Refurbishment. It is also assumed that no HX degradation or failures of the existing HX's will occur prior to HX replacement. If degradation of an existing HX necessitated immediate replacement of the HX, this could have an impact on the project schedule and would require a change to the approved project strategy identified in this BCS. A change to the project strategy could potentially extend project duration in order to rearrange HX replacements around the planned unit outage and refurbishment windows, and necessitate one or more HX's to be replaced during Darlington Refurbishment.

The HX's will be replaced using similar maintenance practices utilized for HX Channel Cover removal. If engineering modifications are required to enable HX replacement (temporary piping supports), the field installation duration will be increased from 40 days to 50 days, and additional time will be required to prepare engineering packages and fabrication piping supports. Therefore, the timeline to replace all 7 HX's will be extended, and the commitments outlined in the BCS will need to be updated to reflect the impact. Contingency has been allocated to this risk.

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Type 3 Business Case Summary

Project #: 16-31710
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release
Document #: D-BCS-33410-10003

Project Cash Flows, NPV, and OAR Approval Amount									
k$	LTD	2017	2018	2019	2020	2021	2022	Future	Total
Currently Released	25,966	12,863							38,829
Requested Now		22,615	16,480	2,212					43,307
Future Required			18,583	12,092	34				30,709
Total Project Cost	25,966	35,478	37,063	14,304	34				112,845
Ongoing Costs	-								
Grand Total	25,966	35,478	37,063	14,304	34				112,845
Estimate Class:	Class 3			Estimate at Completion:	[redacted]				
NPV:	N/A			OAR Approval Amount:	$ 112,845 k				
Additional Information on Project Cash Flows (optional): Annual Cash flows include Contingency									

Approvals			
	Signature	Comments	Date
The recommended alternative, including the identified ongoing costs, if any, represents the best option to meet the validated business need.			
Recommended by (Project Sponsor): Glenn Jager Nuclear President & CNO			16 FEB 2017
I concur with the business decision as documented in this BCS.			
Finance Approval: Ken Hartwick SVP Finance, Strategy, Risk & CFO per OPG-STD-0076			Feb 21, 2017
I confirm that this project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Jeffrey Lyash President & Chief Executive Officer per OAR 1.1			

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

OPG-FORM-0076-R005*

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Business Case Summary

Part A: Business Need

The Shutdown Cooling System is required to remain operational and available through the design life of the station, with no impact on Darlington reliability and safety targets due to equipment failures and/or tritium leaks to the environment.
The baffle supports in all HX's have deteriorated due to MIC. Consequently, the SDC HX tubing is susceptible to damage arising from flow induced vibrations, tube fretting and circumferential cracking. To date, no tubes have leaked*; however, as baffle plate corrosion continues, the risk of a tube leak will increase. A tube leak would result in significantly increased emissions of tritium to the lake, which would be a violation of the environmental and radiation protection requirements of the station Power Reactor Operating License.

*Note: Following replacement of the first HX (2-33410-HX2) in Q3 of 2016, a partial tube side eddy current inspection was performed on the old HX in December 2016 in order to identify the extent of degradation. Results of the inspection indicate that the degradation of the baffle supports had not resulted in any observable damage to the HX tubing. While this inspection indicates the risk of a tube leak is lower than initially expected, it is not necessarily representative of the condition of the remaining 7 HX's that still require replacement. This is further supported by recent OPEX in January 2017 when tube degradation resulted in a tritium leak on HX (1-33410-HX2) as identified in SCR D-2017-00195. This recent event supports the urgency to replace the heat exchangers as soon as possible, as the degradation of each heat exchanger and its remaining service life is unpredictable.

Ultrasonic testing (UT) of the SDC HX shells indicate that the shell wall thickness is reduced in locations due to pitting caused by MIC. Based on the currently estimated corrosion rates for the SDC HX's with the greatest amount of corrosion, the minimum allowable shell wall thickness could be reached at isolated pit locations within 3.5 years (from the time of inspection in 2012), resulting in the operation of the Shutdown Cooling system outside of the design basis.

In order to prevent the onset of additional corrosion pits in the shell and baffle supports, the operating procedure has been revised to enable continuous service water flushing of the SDC HX's during the chlorination season. This improvement will mitigate the onset of MIC in new locations due to stagnant water conditions; however, it will not stop or slow down the corrosion of the SDC HX's at existing pit locations. Eddy Current inspections may be performed on each SDC HX once removed in order to identify any degradation that occurred due to pitting or fretting. This information will be used to plan additional inspections on other SDC HX's in-service, and to enable plugging of degraded tubes to prevent tube leaks. These actions will help to mitigate the risk of a shell or tube side leak; however, they will not eliminate the risk.

The onset of a tube or shell side leak would require the HX to be taken out of service, isolated, and repaired, which would be a loss in redundancy of the Shutdown Cooling system and a reduction in system reliability. A tube side leak could also cause a forced shutdown of a reactor unit, resulting in a loss of production and increasing the Unit Forced Loss Rate. Furthermore, for any planned outage, the unavailability of a SDC HX would increase the time for PHT system cool down, thereby extending outage duration and further increasing the forced loss rate. The unavailability of a SDC HX would also have a negative impact on Unit Refurbishment flow defueling activities, resulting in an increase in the period of time for flow defuel. This would negatively impact Refurbishment outage critical path and overall duration.

The SDC HX's have a service life of 30 years, consequently, replacement of the existing Darlington SDC HX's is required to ensure the continued and reliable operation of the Shutdown Cooling system until the end of station design life (approximately 2055), and thus, support the continued and safe operation of the Darlington reactor units in compliance with the licensing and design basis.

Replacement of the SDC HX's is also a regulatory requirement for completion before the end of the Darlington Life Extension Window, as identified in the Darlington Integrated Implementation Plan [R-5].

Part B: Preferred Alternative: Full Replacement of the Shutdown Cooling Heat Exchangers Prior to Refurbishment

Description of Preferred Alternative

In order to address the ongoing corrosion of the Shutdown Cooling Heat Exchangers and the impending end of service life, a complete replacement of all eight (8) SDC HX's is recommended. Replacement of the SDC HX's will be dimensionally compatible with the existing heat exchangers, and nearly identical from a thermal and hydraulic performance point of view. There will be no change to the tubing (I-800) or shell material (SA516 GR70), and the material chosen for the internal components (segmental baffle plates, tie rods, etc.) will be changed from carbon steel to stainless steel grade 316L, a material more resistant to MIC. The new SDC HX's will have an increased service life of 40 years, thereby ensuring their availability until the end of station life following refurbishment, approximately 2055.

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

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Part B: Preferred Alternative: Full Replacement of the Shutdown Cooling Heat Exchangers Prior to Refurbishment

Description of Preferred Alternative

Each SDC HX will be planned for replacement with the reactor unit at power, and prior to the corresponding reactor unit's planned Refurbishment outage. For specific heat exchangers, this may be not be possible and therefore the heat exchanger will be replaced during the Refurbishment outage or as soon as possible post-Refurbishment in accordance with Darlington Online and Refurbishment work planning processes.

Disposal will be performed by Nuclear Waste Management Division (NWMD).

Deliverables:	Associated Milestones (if any):	Target Date:
This Release • Online Replacement of the 2nd, 3rd and 4th Heat Exchangers. Current replacement sequence is U3HX2→U4HX1→U1HX2 • Refurbishment Replacement of the 5th Heat Exchanger (U2HX1). Replacement Window is undefined but assumed to be within Q1 and Q2 of 2018. • Full Execution Business Case Summary for May 2018 Board Approval for the 6th, 7th and 8th Heat Exchanger Replacements.	***This Release*** 1. Start of Installation – 2nd HX 2. Available for Service Completed – 2nd HX 3. Start of Installation – 3rd HX 4. Available for Service Completed -3rd HX 5. Start of Installation – 4th HX 6. Available for Service Completed – 4th HX 7. Start of Installation – 5th HX 8. Available for Service Completed – 5th HX (contingent upon U2 restart following Refurbishment) 9. BCS Approved	***This Rls.*** 1. 2017-May-29 2. 2017-Aug-18 3. 2017-Aug-21 4. 2017-Nov-10 5. 2017-Nov-06 6. 2018-Jan-26 7. 2018-Apr-30 8. 2019-Oct-30 9. 2018-Jun-15
Future Release • EPC Contract Awarded for Phase 3 of Project • Online Replacement of the 6th, 7th and 8th Heat Exchangers. Current replacement sequence is U1HX1→U4HX2→U3HX1 • Project Complete Milestone	***Phase 3 - Future Release*** 1. Installation Contract Awarded 2. Start of Installation – 6th HX 3. Available for Service Completed – 6th HX 4. Start of Installation – 7th HX 5. Available for Service Completed – 7th HX 6. Start of Installation – 8th HX 7. Available for Service Completed – 8th HX 8. Plan Complete (PCM)	***Phase 3– Fut. Rls.*** 1. 2018-July-30 2. 2018-Aug-07 3. 2018-Oct-26 4. 2018-Nov-05 5. 2019-Jan-25 6. 2019-Jan-31 7. 2019-Apr-23 8. 2020-Oct-30

Part C: Other Alternatives

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

Alternative 2: Base Case: Status Quo – No Project

The option of Status Quo (Do Nothing) is not recommended. Choosing not to pursue a Shutdown Cooling Heat Exchanger replacement, and instead implementing repairs as required, does not represent a permanent solution to corrosion of the shell and internal components, and carries significant Nuclear Safety and Environment Risk.

As the SDC HX's continue to degrade, the likelihood of SDC HX failures due to shell or tube side leaks will increase. A single or simultaneous failure of multiple SDC HX's on one or several reactor units could result in significant tritium emissions to the environment, a reduction in redundancy of the SDC system, and could significantly impair the ability of the SDC system to perform its credited safety function.

Following repair of any HX failure, it cannot be guaranteed that future SDC HX failures will not occur with the same results as identified above. When the number of tubes plugged is more than available margin (60 U-Tubes), the efficiency of the HX will be affected, resulting in increased duration to cool PHT D2O down, hence delaying any planned outage.

This alternative was considered and eliminated, therefore, not included in the financial evaluation.

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Alternative 3: Delay Work – Replacement of SDC HX's during Darlington Refurbishment

The option of delaying the work until Darlington Refurbishment is not recommended.

In order to replace the SDC HX's with the reactor unit online, one SDC HX would be unavailable, while the second SDC HX would be available for use. During replacement of each HX, the SDC system would have a complete loss of redundancy, which could potentially impair the ability of the SDC system to perform its credited safety function. Therefore, the SDC HX's would be replaced during Darlington Refurbishment when the SDC system is not required to be operational. This would eliminate any operational issues associated with a loss of redundancy that is experienced during online SDC HX replacement.

Replacement would be scheduled during the reactor unit refurbishment outages (starting with U2 as early as 2016, U3 in 2019, U1 in 2020 and U4 in 2022), however, this would significantly extend the overall timeline for replacement of all 8 HX's. Based on the degraded condition and the estimated rate of corrosion of the SDC HX's, there is significant risk of a heat exchanger failure occurring during this timeframe. The project was initially scheduled for Darlington Refurbishment; however, based on the urgency to replace the SDC HX's as soon as possible, the project was re-scheduled to take place prior to the start of Darlington Refurbishment. Specific heat exchangers may be replaced during Refurbishment based on challenges in planning and scheduling the work online, however, this will be a contingency measure only.

This alternative was considered and eliminated, therefore, not included in the financial evaluation.

Alternative 4: Purchase Heat Exchangers as Spares, and Replace as Required.

The project would provide the design, fabrication and supply and staging of 8 spare SDC. Based on the degradation observed during the routine HX periodic inspections or based on sudden HX tube leaks that arise, the SDC HX's would be replaced as required. Field execution activities would be managed and funded through the Darlington Operations and Maintenance organization.

This alternative was considered and eliminated, therefore, not included in the financial evaluation.

Alternative 5: N/A

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

k$	LTD	2017	2018	2019	2020	2021	2022	Future	Total
Currently Released	25,966	12,863							38,829
Requested Now		22,615	18,480	2,212					43,307
Future Required			18,583	12,092	34				30,709
Total Project Cost	25,966	35,478	37,063	14,304	34				112,845
Ongoing Costs	-								
Grand Total	25,966	35,478	37,063	14,304	34				112,845

Estimate Class:	Class 3	**Estimate at Completion:**	[redacted]
NPV:	N/A	**OAR Approval Amount:**	$ 112,845 k

Additional Information on Project Cash Flows (optional): Annual Cash Flows include Contingency

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case	Delay Work	Alternative 4	Alternative 5
Project Cost	112,845	N/A	N/A	N/A	N/A
NPV		N/A	N/A	N/A	N/A
Other (e.g., IRR)		N/A	N/A	N/A	N/A

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Summary of Financial Model Key Assumptions or Key Findings:
1. Discount rate (WACC) of 7 % 2. Annual Interest rate of 5% on Capital costs.

Part F: Qualitative Factors
The modification supports Darlington's "Zero Emissions" cornerstone initiative. Interest in nuclear power plant tritium emissions in other countries is expected to generate increased public and regulatory scrutiny going forward. A significant tritium emission to the lake as a result of a tube leak would have a detrimental impact on public support for nuclear power in the community.

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	There is a risk that the HX's cannot be replaced using similar maintenance practices as are utilized for HX Channel Cover removal. If engineering modifications are required to enable HX replacement (temporary piping supports), the field installation duration will be increased from 40 days to 50 days, and additional time will be required to prepare engineering packages and fabricate piping supports. Therefore, the timeline to replace all 7 HX's will be extended, and the commitments outlined in the BCS will need to be updated to reflect the impact. There is a risk that the OPG resource costs and Vendor equipment and resource costs are underestimated, resulting in project expenditures exceeding approved funding release and requiring project activities to be placed on hold.	Accept: For each remaining HX installation, [redacted] of contingency has been allocated to the risk of designing and installing engineering modifications associated with temporary piping supports for seismic and CIWH loadings. Mitigate: 1. A weekly review of project expenditures, forecasted costs, and project risks is performed in order to evaluate the cost performance of the project and to determine if project contingency needs to be requested, or an additional project funding release is required. 2. Cash expenditures and resource allocations from the 1st HX installation were utilized to develop the current project cost estimate and to assign specific contingency for the realization of project risks.	Low	Medium
Scope	There is a risk that discovery issues on existing PULSW or SDC system components that will not be replaced as part of this project may lead to added scope for replacement or cause delays during execution to address.	Mitigate: 1. Known issues with degraded piping and components on the PULSW system and SDC system have been communicated to the Station in order to ensure these items are addressed prior to field execution (E.g. replacement of degraded PULSW isolation valves). 2. Pre-requisite activities for construction include Ultrasonic Inspection of piping cut locations to ensure appropriate wall	Low	Medium

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Part G: Risk Assessment				
Risk Class	**Description of Risk**	**Risk Management Strategy**	**Post-Mitigation**	
		thickness is available and to adjust location and/or plan for mitigating activities if required. 3. Contingency materials and components have either been purchased by the project, or requested from OPG inventory for items that may pose challenges during construction.		
Schedule	There is a risk of discovery issues, station/unit transients, and/or extreme summer or winter conditions causing delays during field execution window, and resulting in an extension to the 40 day field execution duration.	Mitigate: 1. Detailed walk downs performed by engineering and construction leads in order to validate field configuration and to minimize the risk of discovery issues during execution. 2. Breathing Air system and Vault Cooling System preventative maintenance will be prioritized with Station Operations and Maintenance in order to ensure acceptable performance during scheduled summer and winter HX replacements. In addition, specific contingency has been assigned to each HX installation to account for increased field execution duration.	Medium	Medium
Resources	There is a risk that the installation timeline conflicts with other work being done inside the station (e.g PULSW Piping Replacement), and as a result field execution work is delayed (until required resources are available) or field execution is extended (work of higher priority may be in execution inside the station that will interfere with the project, be it conflict in resource allocation, use of space, or use of equipment). A key concern is with Refurbishment or Planned Outage related activities, which may be scheduled to take place in parallel with this project.	Mitigate: 1. Communicate and engage affected OPG work groups well in advance to ensure support will be available during the required time. 2. Schedule tasks where possible when resources will be available. (I.e. outside of planned outages). 3. Ensure WO's are provided to Work Control in accordance with the N-PROC-MA-0022 timelines for Project Work. 4. During periods of inactivity on this project, the vendor will attempt to retain key skilled resources by assigning them to different projects that are in execution.	Medium	Medium
Quality/ Performance	There is a risk that the Design Engineering Change (EC) Packages are of poor quality and lack the necessary detail, and/or the construction activities are performed poorly, thus leading to delays because of rework.	Mitigate: 1. 3rd Party Review of Engineering Change packages. 2. Constructability reviews of EC packages by Construction Staff prior to approval. 3. Field Initiated Changes from the 1st HX installation are being incorporated into revisions of EC packages for the remaining 7 HX's. This will be repeated as required following each installation to incorporate Lessons Learned. 4. A Weld Mock-up of the HX nozzle to SDC piping connection will be built and utilized to train welding staff on critical welding activities prior to execution in the field.	Low	Medium
Technical	There is a risk that the tooling and equipment used for lifting and transporting the old & new HX out	Mitigate: 1. Tooling and Equipment will be inspected and tested prior to use on site. Issues identified	Low	Medium

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
	of/into the station, flushing and drying the old HX, and installing the new HX will require troubleshooting once installed, thereby negatively impacting schedule / work quality.	with the tooling and equipment during the 1st HX replacement have been incorporated into Lessons Learned and will be addressed prior to subsequent HX replacements.		

Additional Risk Analysis:

[See Guidance Section in the Appendix pages for detailed Part G instructions.]

Part H: Post Implementation Review (PIR) Plan

Type of PIR Report	Target In-Service or Completion Date	Target PIR Completion Date
Comprehensive PIR	2020-10-30 (Project Completion)	2021-10-30

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Replace all SDC HX's (Qty=8) in all four Darlington Units (1, 2, 3 &4)	Current SDC HX's have experienced accelerated degradation of internal tube support structures and shell material due to MIC.	SDC HX's are more resistant to MIC degradation and their service life is sufficient to reach the projected end of Darlington operation.	Installation of new SDC HX's containing internal components (tube support structures) with greater resistance to MIC, and with a service life of 40 years.	Darlington Components & Equipment Engineering
Operation of SDC HX's	The operation of the SDC HX's pose a risk of tritium leaks to the environment, and could limit the SDC system's ability to cool down the PHT system, or limit its ability to provide maintenance cooling as a result of reduced thermal performance caused by secondary side fouling and degraded baffle plates.	The operation of the SDC HX's does not limit the SDC system's ability to cool down the PHT system, or limit its ability to provide maintenance cooling.	Evaluation of the SDC system operation during its first use following replacement of a SDC HX.	Darlington Components & Equipment Engineering

Part I: Definitions and Acronyms

ALARA – As Low as Reasonably Achievable
BCS – Business Case Summary
COMS – Constructability, Operability, Maintainability and Safety
EC – Engineering Change
ECC – Engineering Change Control
EM - Equipment Manufacturer
EPC - Engineer Procure Construct
ES MSA – Extended Services Master Service Agreement
HX - Heat Exchanger
PHT– Primary Heat Transport
IMS – Inspection & Maintenance Services
MIC - Microbiologically induced corrosion
NWMD - Nuclear Waste Management Division
PMP – Project Management Plan
PO - Purchase Order
PULSW – Powerhouse Upper Level Service Water System
SDC - Shutdown Cooling
UT - Ultrasonic Testing
WWMF – Western Waste Management Facility

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

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Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

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Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Appendix A: Summary of Estimate										
Project Number:	16-31710									
Project Title:	Darlington Shutdown Cooling Heat Exchanger Replacement									
k$	**LTD**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Future**	**Total**	**%**
1. OPG Project Management	971	483	630	271	34	-	-	-	2,389	2
2. OPG Design	528	147	153	151	-	-	-	-	979	1
3. OPG Procured Materials	-	-	-	-	-	-	-	-	-	-
4. OPG Other	3,066	2,954	3,244	1,243	-	-	-	-	10,507	9
5. EPC - Design	[redacted]									
6. EPC - Procurement										
7. EPC - Construction										
8. EPC - Project Management										
9. Interest										
Subtotal										
Contingency										
Total	25,965	35,479	37,063	14,304	34	-	-	-	112,845	100

Note: NWMD is responsible for the transport of the SDC HX's off-site to either the Western Waste Management Facility (WWMF) for long term storage, or to an external vendor for recycling and waste volume reduction. Management and funding of these activities is provided by NWMD, and therefore the associated expenditures are not included in the Estimate at Completion, or in the Removal Costs.

Notes			
Project Start Date	2012-06-29	**Total Definition cost** (excludes unspent contingency for Nuclear)	[redacted]
Target In-Service (or AFS) Date	2019-10-30 Final AFS	**Contingency included in this BCS** (Nuclear only)	
Target Completion Date	2020-10-30 Project Completion	**Total contingency released plus contingency in this BCS** (Nuclear only)	
Escalation Rate	2.90%	**Total released plus this BCS without contingency** (Nuclear only)	
Interest Rate	5.0%	**Total released plus this BCS with contingency** (Nuclear only)	$ 82,136 k
Removal Costs	$24 M included	**Estimate at Completion** (Includes only spent contingency for Nuclear)	[redacted]

Prepared by:	Approved by:
James Philipps FEB 13, 2017 Date	Marc Clemente Feb 13, 2017 Date
James Philipps Darlington and Refurbishment Projects Project Leader II	Marc Clemente Darlington and Refurbishment Projects Acting Section Manager

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Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

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

Comparison of Total Project Estimates

Phase	Release	Approval Date	Total Project Estimate in k$ (by year including contingency)						Future	Total Project Estimate
			2012	2013	2014	2015	2016	2017		
Definition	Partial	Nov 2012	19	1,314	18,858	15,977	6,505	3,696	1,160	47,529
Definition & Execution	Partial	March 2014	5	511	2,268	6,255	17,728	14,605	14,713	56,085
Execution	Partial	March 2017	5	511	962	2,374	22,113	35,479	51,401	112,845

Project Variance Analysis

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
1. OPG Project Management	971	4,500	2,389	(2,111)	The increase in support for the extended project duration was offset by the removal of some costs (Field Engineering, Contract Management staff) that were reallocated to 'OPG Other'.
2. OPG Design	528	642	979	337	Increased to capture design oversight for EC revisions to address new scope items.
3. OPG Procured Materials	-	-	-	-	N/A
4. OPG Other	3,066	5,466	10,507	5,041	Reallocated Field Engineering and Contract Management staff from 'Project Management.' Increased to capture additional costs associated with 40 day execution window.
5. EPC - Design	[redacted]				
6. EPC - Procurement					
7. EPC - Construction					
8. EPC - Project Management					
9. Interest					
Subtotal					
Contingency					
Total	**25,966**	**56,085**	**112,845**	**56,760**	

Type 3 Business Case Summary

Project #: 16-31710 Document #: D-BCS-33410-10003
Project Title: Darlington Shutdown Cooling Heat Exchanger Replacement, <Partial> <Execution> Release

Appendix C: Financial Evaluation Assumptions

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

Project Cost:

1. The replacement heat exchangers will be identitical in design to the existing heat exchangers (except for internal supports changed to MIC resistant material), and therefore there will be no changes to the current thermal and stress analysis of the shutdown coolilng heat exchangers. The shell material will remain unchanged [R-3].
2. OPG internal cost estimate was developed in house and covers all phases of the project.

Financial:

1. Annual Interest Rate of 5% on capital costs.

Project Life:

1. The new Shutdown Cooling Heat Exchangers shall have a 40 year design life so that they remain operational until the end of station life following refurbishment, approximately 2055.

Energy Production:

N/A

Operating Cost:

N/A

Other:

N/A

List further detail below as appropriate from the Financial Evaluation:

N/A

Appendix D: References

[R-1] D-PCH-33410-10001, Project Charter
[R-2] NK38-PLAN-39780-0489198, Project Management Plan
[R-3] NK38-CORR-33410-0444878, Memo Re: SDC HX Replacement Project
[R-4] NK38-REP-33410-10016-R004, CCA 001465-system 0067 Shutdown Cooling-heat Exchangers
[R-5] NK38-REP-03680-10185-R000, Darlington NGS – Integrated Implementation Plan (IIP)
[R-6] NK38-CORR-33410-0462000, Project 16-31710- RS Impact Of Unavailability Of Shutdown Cooling Hx's During Replacement

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

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Type 3 Business Case Summary

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

Executive Summary and Recommendations

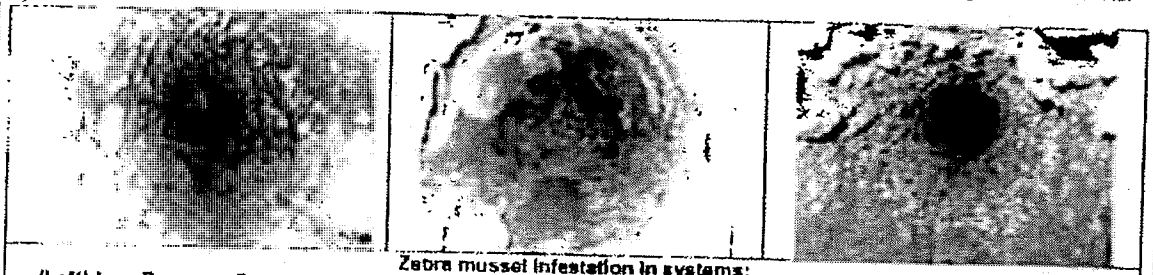
Project Information			
Project #:	16-38948	Document #:	D-BCS-72100-10006
Project Title:	DN Zebra Mussel Mitigation Improvements		
Class:	☐ OM&A ☒ Capital ☐ Capital Spare ☐ MFA ☐ CMFA ☐ Provision ☐ Others:	Investment Type:	Sustaining
Phase:	Execution	Release:	Superseding
Facility:	Darlington	Target In-Service or Completion Date:	2017-08-30

Project Overview

We recommend the Gate 3b approval to proceed and release of $7,774k, including [redacted] contingency for the Zebra Mussel Mitigation Project. The total project is estimated at $29,255k including [redacted] contingency. This is a Class 2 estimate for this release and a Class 2 estimate for the entire project.

Issue:

Zebra mussel fouling has impaired the reliability of plant systems that use lake water, due to the undesired presence of the invasive freshwater mussel. These service water systems provide cooling water to a number of safety and safety related loads such as shutdown cooling heat exchangers, shutdown cooling pump motor coolers, moderator heat exchangers, liquid zone control, and critical air conditioning units. See below for examples of zebra mussel infestation in the Darlington Service Water systems.



Zebra mussel infestation in systems:
(Left) Low Pressure Service Water (LPSW) booster pump 4-72100-P5, (Middle) Powerhouse Upper Level Service Water (PULSW) 1-72300-NV317, and (Right) PULSW 1-72300-V195

A World Association of Nuclear Operators (WANO) evaluation at Darlington identified as an area for improvement (AFI) as zebra mussel fouling in low-flow end stagnant areas.

Total project cost changes are attributed to scope change via four Project Charter Revisions since the start of the project. The Full Execution scope change is related to the completion of feasibility studies for implementing closed loop supply for Primary Heat Transport (PHT) & Shutdown Cooling (SDC) pump motor cooling and replacement of Low Pressure Service Water (LPSW) Strainers in these systems and completion of the scope definition phase for installing strainers on Powerhouse Upper Level Service Water (PULSW) & LPSW supply to safety and safety related loads in critical systems. In the requested release, a design change is needed to relocate the permanent Sampling Station from the roof of the Condenser Cooling Water (CCW) structure to ground level to maintain safe work conditions during winter conditions. In addition, the conversion of the temporary modification (TMOD) to a permanent modification (PMOD) for the Inactive Drainage Lagoon aeration system is needed to ensure the total residual chlorine (TRC) is maintained below the MOE limits as a result of 4-unit continuous chlorination.

The original design was ineffective at controlling zebra mussel infestation as it allowed intermediate chlorination (ability to chlorinate only one LPSW unit pump house & the ESW pump house). This enhanced design (Master Design EC 122616 &

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

Type 3 Business Case Summary

Project #: 16-38948
Project Title: DN Zebra Mussel Mitigation Improvements, Superseding Execution Release

Document #: D-8CS-72100-10006

Project Overview

122617) improves the reliability of the existing system and allows 4-unit continuous chlorination and the installation of a permanent dechlorination system that would naturalize the chlorine concentration at the outfall before releasing to the environment.

Below are details in the change of scope from each previous release:

Scope of work for Partial Definition release (total project cost was [redacted], plus [redacted] of contingency):

1) Value Engineering Sessions for the full project scope
2) Scope Definition phase (modification Design Requirements (MDRs), Master ECs, Design Scoping Check lists & associated forms for 4-unit Chlorination & Permanent De-Chlorination.
3) Request for Purchase (RFP) packages completed & Proposals obtained via competitive bids.

Scope of work for Partial Definition & Execution release (total project cost was [redacted], plus [redacted] of contingency):

1) Bridging strategy with temporary de-chlorination to support 4- unit continuous chlorination has been completed and placed into service.
2) Detailed design for permanent de-chlorination and piping upgrades for chlorination system improvement has been completed.

Removal from the Scope of work for Full Execution release (total project cost was [redacted], [redacted] of contingency):

1) Complete feasibility studies for implementing closed loop supply for Primary Heat Transport (PHT) & Shutdown Cooling (SDC) pump motor cooling and replacement of Low Pressure Service Water (LPSW) Strainers in these systems.

2) Complete scope definition phase (Modification Design Requirements/MDR, Modification Outline/MO and associated forms) for installing strainers on Powerhouse Upper Level Service Water (PULSW) & LPSW supply to safety and safety related loads in critical systems.

Additional Scope of work for the Superseding release (total project cost is [redacted], plus [redacted] of contingency):

1) The MDR for de-chlorination system (NK38-MDR-74950-10003) has been revised to include design change for permanent sampling station. The additional design effort to relocate permanent sampling station to ground level to address worker/personnel safety related concerns has increased the project total by $1,733k and changed the permanent sampling station ready date to the 2017 chlorination season.

2) The design conversion of the TMOD to a PMOD for the Inactive Drainage Lagoon aeration system will be completed in-house by the OPG design team. The design effort along with the purchase of the new aeration system and the installation costs has increased the project cost by $290k.

Recommendation:

We recommend the gate 3b approval to proceed and release of a $7,774k, including [redacted] for a Superseding Release of the Zebra Mussel Mitigation Improvements project.

This release will fund the following scope of work:

- Complete Installation, Commissioning, and Final AFS of the 4-unit (continuous) chlorination and (permanent) de-chlorination modification.
- Conversation of the TMOD to a PMOD for the Inactive Drainage Lagoon aeration system and purchase of equipment for the permanent aeration system.
- Design, Installation, and Final AFS of the Sampling Station
- Project close-out

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Type 3 Business Case Summary

Project #: 16-38948
Project Title: DN Zebra Mussel Mitigation Improvements, Superseding Execution Release
Document #: D-BCS-72100-10006

Project Cash Flows, NPV, and OAR Approval Amount

k$	LTD	2016	2017	2018	2019	2020	2021	Future	Total
Currently Released	10,889	10,592							21,481
Requested Now	-	5,750	1,952	72					7,774
Future Required	-								
Total Project Cost	10,889	16,342	1,952	72					29,255
Inventory			204						204
Ongoing Costs	-		750	750	750	750	750	3,750	7,500
Grand Total	10,889	16,342	2,906	822	750	750	750	3,750	36,959

Estimate Class:	Class 2	**Estimate at Completion:**	[redacted]
NPV:	N/A	**OAR Approval Amount:**	$36,959k

Additional Information on Project Cash Flows (optional):
Spare parts inventory for new installed chlorination & de-chlorination systems is estimated at $204k
Ongoing chemical (sodium hypochlorite (NaOCl) & Sodium Bi-sulphite (SBS)) cost is estimated at $750k per year.

Approvals

	Signature	Comments	Date
The recommended alternative, including the identified ongoing costs, if any, represents the best option to meet the validated business need.			
Recommended by (Project Sponsor): Glenn Jager Nuclear President, and CNO			SEP 28 2016
I concur with the business decision as documented in this BCS.			
Finance Approval: Ken Hartwick SVP Finance, Strategy, Risk & CFO per OPG-STD-0076			Sept 29, 2016
I confirm that this project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Jeff Lyash President & CEO per element 1.1			Oct 3/16

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

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Type 3 Business Case Summary

Project #: 16-38948
Project Title: DN Zebra Mussel Mitigation Improvements, Superseding Execution Release

Document #: D-BCS-72100-10006

Business Case Summary

Part A: Business Need

Zebra mussel fouling has been an issue in service water systems effecting equipment reliability. Service water provides cooling to a number of safety and safety related loads such as shutdown cooling heat exchangers, shutdown cooling pump motor coolers, moderator heat exchangers, liquid zone control, and critical air conditioning units. Zebra mussel fouling can and has in the past resulted in unavailability of this equipment.

Zebra mussel fouling has resulted in unavailability of the shutdown cooling pumps on numerous occasions. Zebra mussel fouling has also resulted in debris blocking cooling lines, significant vault vapour recovery heat exchanger fouling and flow blockage. Other systems that were also affected by zebra mussels fouling were liquid zone control heat exchangers, vault coolers, confinement dryer heat exchangers and primary heat transport pump motor coolers. Flow blockages are typically a result of zebra mussel debris being introduced into these systems as a result of valving in of stagnant lines such as use of the LPSW inter-unit tie and PULSW recirculation at Darlington.

Zebra mussels are an invasive species not native to North America. Accordingly, the original design of the Darlington service water systems did not consider the need for zebra mussel mitigation and hence zebra mussel infestation became a problem after the service water systems were put in service. Presence of adult zebra mussels in station piping indicated that they are entering as veligers and growing to adulthood inside the piping over a period of time.

There is a significant increase of Station Condition Records (SCRs) trending over the past 8 years relating to low flow and pressure due to zebra mussel fouling such as LPSW Supply line to Instrument Air Compressors Cooling, PULSW Supply lines to Shutdown Cooling, and zebra mussels found in pump housing/piping.

Zebra mussel fouling in low flow and stagnant areas was the basis for an Area for Improvement (AFI) in Darlington's previous World Association of Nuclear Operators (WANO) evaluation.

A chlorination system was completed years ago to control zebra mussels but the frequencies of chlorination dosing (semi-continuous) were not adequate over time for effective zebra mussel control due to zebra mussels adapting to the dosing frequencies. Therefore implementation of continuous chlorination across all units is required to ensure effective zebra mussel control while maintaining Ministry of Environment (MOE) limits/requirements for outfall into lake.

There is also an operability reliability risk with the current service water chlorination system which presently have two types of sodium hypochlorite piping:

- Chlorinated Polyvinyl Chloride (CPVC), which has shown numerous leaks with the majority on threaded or glued joints; and,
- Polyvinyldiene Fluoride (PVDF) piping, that has reached its end of design life.

Pickering station has implemented a De-Chlorination Systems to support continuous chlorination to eliminate zebra mussels fouling in service water systems. Operating Experience (OPEX) from the Pickering project scope is used for implementation at Darlington.

A Service Water Reliability Program – Strategy Manual completed in 2012 identified a program for minimizing/eliminating challenges to equipment reliability and plant operation due to zebra mussel fouling (as one of the factors) that may occur in open service water systems. Condition Assessments & Self-Assessments were completed in the past to identify areas for improvements with regards to Service Water Reliability Program and zebra mussel fouling. A short & long term strategy/program has been put in place to address service water reliability issues which include this project scope.

The business objective of this sustaining project is to:

1) Upgrading existing service water chlorination systems. These presently have two types of sodium hypochlorite piping; CPVC Piping which has shown numerous leaks & PVDF Piping which has reached its end of life.
2) Prevent zebra mussel attachment to service water equipment (Emergency Service Water (ESW), LPSW, PULSW) downstream of chlorination points.
3) Implement continuous chlorination across all units. The present dosing schedule provides semi-continuous 90 minutes ON, 270 minutes OFF (in unit pump houses) and continuous in ESW pump house during the zebra mussel season (May to December).
4) Meeting ministry of Environment (MOE) limits for outfall.
5) Eliminate introduction of zebra mussel debris in critical station systems to prevent potential PULSW & LPSW outages which could result in unit outage extensions.

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

Type 3 Business Case Summary

Project #: 16-38948
Project Title: DN Zebra Mussel Mitigation Improvements, Superseding Execution Release
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Part B: Preferred Alternative: Implementation of the Recommended Modifications

Description of Preferred Alternative

During the initiation phase of the project a vendor was consulted to evaluate the issues & mitigation improvements of Zebra Mussel fouling in Service water systems. A conceptual design report was issued which addresses various areas in the Darlington service water systems. Value engineering sessions were also held to refine and prioritize the scope of the project considering their impact on the station and associated risks.

As per the project charter (D-PCH-72100-10003), there was no scope drop from previous releases. However there was additional scope that increased that total project cost as per the following:

- Revise the design for the permanent sampling station to relocate from the top of the CCW discharge structure to ground level. This additional scope increased the total project cost by 1.1M.
- Prepare a temporary modification (TMOD) to support aeration system in the IAD lagoons and rent the aeration equipment for the 2016 chlorination season. This additional scope increased the project cost by 290k.

The original design that allowed intermediate chlorination (chlorinate one LPSW unit pump house & the ESW pump house) was ineffective at controlling zebra mussel infestation especially during the worm summer months due to the high LPSW & ESW system flow rates. The additional scope, as identified above, was approved to support this modification (Master Design EC 122616 & 122617) to allow 4-unit continuous chlorination and the installation of a permanent dechlorination system that would naturalize the chlorine concentration at the outfall before releasing to the environment.

The recommended modifications are to be implemented as part of the long term strategy/program for eliminating & preventing zebra mussel fouling in station service water systems. The scope of this project is restricted to complete:

A - Liquid Chlorination System Improvement

1) CPVC Chlorination piping to be replaced with new PVDF piping.
2) Replacement of existing PVDF chlorination piping with new PVDF Piping since its reaching its end of life.

   Implementation of 4-unit (continuous) chlorination including an automatic interface with a permanent de-chlorination system.

B - De-chlorination System Installation

1) Installation of a new (permanent) de-chlorination system to permit 4-unit (continuous) chlorination.

Deliverables:	Associated Milestones (if any):	Target Date:
Complete 4-Unit Chlorination and Permanent De-Chlorination Modifications AFS.	Chlorination/De-Chlorination – Final AFS (AFS)	30Jan17
Available For Service for PMOD of IAD Aeration System	IAD Aeration System – Final AFS (AFS)	30DEC16
Complete revised Design of Sampling Station	Design Completion	14MAR17
Start of Installation for Sampling Station	Sampling Station – Start Of Installation (SOI)	12JUN17
Available For Service of the Sampling Station	Sampling Station – Final Available For Service (AFS)	30AUG17
Project Closeout	Project Closeout	11SEP18

Part C: Other Alternatives

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

Alternative 2: Base Case – No Project

Failure to complete this modification would result for the continued need for outage extensions due to the need for LPSW outages: 4 days outage extensions per planned outage for LPSW for 2/3 of Darlington Nuclear (DN) Outages to effect zebra mussel abatement. These outages would have to take place at the end of each outage when heat loads are lowest. This option

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Alternative 2: Base Case – No Project

would reduce the reliability of the Service Water Systems and zebra mussel fouling could increase due to no continuous chlorination. In addition, it would also increase maintenance to attempt to continue manage the leaks through vigorous maintenance procedures.

Alternative 3: Delay Work – Delay Work

Station has OPEX and a history of adverse conditions relating to zebra mussels and zebra mussel debris fouling the service water systems cooling lines. Zebra mussel fouling has been an issue in service water systems effecting equipment reliability and resulting in unavailability of safety and safety related systems. Delaying this project increases the risk of re-occurring events which could potentially de-rate units.

Alternative 4: Implement portion of the scope.

Implement the 4-unit (continuous) chlorination modification only and continue to use the temporary de-chlorination system currently in service i.e. do not implement the (permanent) de-chlorination system. However, this alternative is not a long term viable option for the station due to the following:

- Current temporary de-chlorination system was designed to support two-unit continuous chlorination only.
- There will be lack of (automatic) communication interface between the chlorination system and the de-chlorination system. Lack of automatic systems creates the risk scenario if the de-chlorination system becomes impaired; the continuous chlorination would not stop and could result in exceeding ministry of environment limits. Current de-chlorination injection rates are based on manual inspections and operator rounds necessitating significant human intervention. There is a potential risk of human error.
- Increase storage of chemicals. No space available to store more chemicals using rental equipment.
- Potential costs increases in the long term due to rental of equipment, associated mobilization and demobilization costs incurred each season and increase of oversight to support the de-chlorination system vendor with day to day operation of the system.

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

k$	LTD	2016	2017	2018	2019	2020	2021	Future	Total
Currently Released	10,889	10,592							21,481
Requested Now	-	5,750	1,952	72					7,774
Future Required	-								
Total Project Cost	10,889	16,342	1,952	72					29,255
Inventory			204						204
Ongoing Costs	-		750	750	750	750	750	3,,750	7,500
Grand Total	10,889	16,342	2,906	822	750	750	750	3,750	36,959

Estimate Class:	Class 2	**Estimate at Completion:**	[redacted]
NPV:	N/A	**OAR Approval Amount:**	$36,959k

Additional Information on Project Cash Flows (optional):

Spare parts inventory for new installed chlorination & de-chlorination systems is estimated at $204k.
Ongoing chemical (sodium hypochlorite (NaOCl) & Sodium Bi-sulphite (SBS)) cost is estimated at $750k per year.

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case	Delay Work	Alternative 4	Alternative 5
Project Cost	$29,255				
NPV	N/A				
Other (e.g., IRR)					

Summary of Financial Model Key Assumptions or Key Findings:

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Summary of Financial Model Key Assumptions or Key Findings:
Sustaining Investment, NPV not required.

Part F: Qualitative Factors
- WANO evaluation of Darlington Station for Areas of Improvement - Reliability of Darlington Station Systems/Equipment.

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	There is a risk of the Sampling Station Design will not be complete within the budgetary quote provided due to a low quality estimate. This will inherently increase the cost of the design.	Estimates are based on design work completed and that contingency has been set aside for unforeseen conditions and/or delays.	Medium	Medium
Scope	Due to incomplete sampling station design, budgetary quote for installation may be inadequate. This may increase cost and delay execution.	Contingency will be allocated for Sampling Station installation.	Medium	Medium
Scope	Numerous design changes and discovery work during the chlorination installation have resulted in cost increase/schedule delays. There is a risk that these design changes may be applicable to the de-chlorination system as well.	This risk can be mitigated through engineering oversight and vendor design agency on site to minimize any design impact.	Medium	Medium
Schedule	There is a risk of not achieving Final AFS for the 4-unit Chlorination/De-chlorination post commissioning due to potential Open Items developed from commissioning.	This risk can be mitigated by engaging stakeholders prior to AFS to disposition/resolve any potential open items.	Low	Medium

Additional Risk Analysis:
N/A

Part H: Post Implementation Review (PIR) Plan

Type of PIR Report	Target In-Service or Completion Date	Target PIR Completion Date
Comprehensive PIR	2017-08-30	2018-09-11

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
Number of Leaks on Chlorination Piping	Approximately 35 leaks on CPVC Chlorination during 3 years of operation	Leaks will be significantly reduced by 90%	Comparisons of Corrective Maintenance WOs before and after mod. implementation	Performance Engineering, Chlorination SRE
Residual Chlorine in LPSW outfall	Residual chlorine is being discharged in the LPSW outfall	Reduce residual chlorine level to current acceptable level for allowing 4 unit chlorination	Residual levels: Below limit set in the Certificate of Authorization	Chemistry and Environment
Adult Zebra Mussels found in the LPSW System	Live adult zebra mussels found in the LPSW Bioboxes	Zero live adult zebra mussels found in the LPSW Bioboxes and during the D1711	Observation of Bioboxes and field observations from the D1711 PULSW	Chlorination Program Co-ordinator Or

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Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
		PULSW Outage	Outage	Chlorination SRE

Part I: Definitions and Acronyms

PHT: Primary Heat Transport
PVDF: Polyvinylidene Fluoride
CPVC: Chlorinated Polyvinyl Chloride
SDC: Shutdown Cooling
PULSW: Powerhouse Upper Level Service Water
LPSW: Low Pressure Service Water
ESW: Emergency Service Water
AFS: Available for Service
RCW: Re-circulated Cooling water
MOE: Ministry of Environment
EPC: Engineering, Procurement, Construction
WANO: World Association of Nuclear Operators
AFI: Area for Improvements
EC: Engineering Change
OPEX: Operating Experience
MDR: Modification Design Requirements

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Appendix A: Summary of Estimate										
Project Number:	16-38948									
Project Title:	DN Zebra Mussel Mitigation Improvements									
K$	LTD	2016	2017	2018	2019	2020	2021	Future	Total	%
OPG Project Management	1,441	162	160	[redacted]					1,802	6
OPG Engineering (including Design)	1,130	170	189						1,489	5
OPG Procured Materials										
OPG Other	398	135	59						592	2
Design Contract(s)	[redacted]									
Construction Contract(s)										
EPC Contract(s)										
Consultants										
Other Contracts/Costs										
Interest										
Subtotal										
Contingency										
Total	10,889	16,341	1,952	72					29,255	100

Notes			
Project Start Date	2013-01-03	Total Definition cost (excludes unspent contingency for Nuclear)	[redacted]
Target In-Service (or AFS) Date	2017-08-30	Contingency included in this BCS (Nuclear only)	
Target Completion Date	2018-09-11	Total contingency released plus contingency in this BCS (Nuclear only)	
Escalation Rate	2.5%	Total released plus this BCS without contingency (Nuclear only)	
Interest Rate	5.0%	Total released plus this BCS with contingency (Nuclear only)	$29,255k
Removal Costs	$60k	Estimate at Completion (includes only spent contingency for Nuclear)	[redacted]

Prepared by:		Approved by:	
P. Hetzel	2016-03-22	[signature]	2016-03-28
Philip Hetzel Engineering Intern Design Projects	Date YYYY-MM-DD	Rajbir Singh (Acting) Manager Refurb and Outage Projects	Date YYYY-MM-DD

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

Comparison of Total Project Estimates

Phase	Release	Approval Date	Total Project Estimate in k$ (by year including contingency)						Future	Total Project Estimate
			2013	2014	2015	2016	2017	2018		
Definition	Partial	2012-11-30	631	4,396	5,537	2,562	2,268	2,231	1,254	18,879
Definition & Execution	Partial	2014-03-29	323	10,587	7,423	5,448	1,169	2,095	11,259	38,303
Execution	Full	2015-10-07	323	2,491	12,643	5,642	382	0	0	21,481
Execution	Superseding	Q3 2016	323	2,492	8,075	16,341	1,952	72	0	29,255

Project Variance Analysis

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management	1,441	1,817	1,802	(15)	Project Management costs were previously over estimated. Project Closeout is requested one year later than last BCS.
OPG Engineering (including Design)	1,130	1,500	1,489	(11)	Variance due re-location of the Sampling Station, additional Design is required to complete the modification.
OPG Procured Materials					
OPG Other	398	0	592	592	OPG Other costs were divided between OPG PM and ENG costs in the previous release. These include Station support during the installation.
Design Contract(s)	[redacted]				
Construction Contract(s)					
EPC Contract(s)					
Consultants					
Other Contracts/Costs					
Interest					
Subtotal					
Contingency					
Total	22,979	21,481	29,255	7,774	

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Appendix C: Financial Evaluation Assumptions
Key assumptions used in the financial model of the Project are (complete relevant assumptions only):
N/A

Appendix D: References
1) Charter: D-PCH-72100-10003 R003
2) Conceptual Design Report: NK38-DRT-72100-10009
3) Value Engineering Study: NK38-REP-72100-0478327
4) ESW & LPSW Chlorination Upgrade MDR: NK38-MDR-74950-10004.
5) Installation of Permanent De-Chlorination System MDR: NK38-74950-10003
6) Zebra Mussel Mitigation Improvements – Phase I (4-Unit Continuous Chlorination and De-Chlorination) Scope of Work NK38-SOW-74950-10002.

Type 2 Business Case Summary

To be used for investments/projects meeting Type 2 criteria in OPG-STD-0076.

Project Information			
Project #:	16-80022	**Document #:**	D-BCS-60800-10005 R000
Project Title:	OH180 Aging Management Hardware Installation		
Class:	☐ OM&A ☒ Capital ☐ Capital Spare ☐ MFA ☐ CMFA ☐ Provision ☐ Others:	**Investment Type:**	Sustaining
Phase:	Definition	**Release:**	Full
Facility:	Darlington	**Target In-Service or Completion Date:**	Q4, 2027

Project Overview

We recommend the release of $5,892k, including [redacted] of contingency

The total project release to date is $7,290k, including [redacted] of contingency

The estimated total project cost is $90,032k, including [redacted] of contingency. At this initial phase of the project there is significant risk on the execution, planning, and resourcing estimates. The scope is significant with 1344 controllers to be isolated, power supplies and boards swapped out, and function testing performed. Some of the controllers require a 4 unit outage and others impact multi-units. Conservative decision for this Business Case Summary was to include full amount of contingency (100%) in the future release. After the project has executed the pilot phase and obtained relevant OPEX, future releases will incorporate this OPEX into the costing and the contingency will be reduced and in alignment with a Class 3 estimate.

The total cost of the OH180 aging management programme, including the nearly complete project to reverse engineer and qualify replacement components is $95,086k, including [redacted] contingency.

The quality of the estimate for this release is Class 3, and for the total project is Class 4

This release will fund the following scope of work:

- Work planning, including detailed installation/commissioning work plan preparation and work order task assessments, for OH180 Programmable Controllers (PK) online replacements in 2017 and Online/Outage replacements in 2018
- Materials procurement for online replacements in 2017 and Online/Outage replacements in 2018
- Field replacement of approximately 3% of total PKs in 2017 as a pilot execution
- Preparation and approval of Execution Partial Business Case Summary (BCS) for next phase (year 2018 to 2020) PK replacements

History of BCS releases and project cost estimates:

The total project cost is now estimated at $90,023k, including [redacted] contingency, compared to $47,203 k, including [redacted] of contingency in the previous release.

History of scope and schedule changes:

The proactive replacement of all fibre optic transceiver boards in the OH180 Communication Modules (2 boards per module) has been added to the scope of this project following review of aging management strategy with the project sponsor.

The target date for full AFS of all PK replacements is now 2027, compared to 2022 in the previous BCS. The variance is due to completing this work in planned unit outages, as opposed to Refurbishment outages assumed previously, and also due to a significant number of PKs that require four unit shutdown, that will need to be replaced during VBO in 2027.

Part A: Business Need

The OH180 Programmable Logic Controller (PK) is an essential piece of plant equipment at Darlington. It was designed by Ontario Hydro (OPG's predecessor) and built by a third party manufacturer to replace the electro-mechanical relays used for

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Type 2 Business Case Summary

Project #: 16-80022 Document #: D-BCS-60800-10005 R000
Project Title: OH180 Aging Management Hardware Installation, <Full> <Definition> Release

Part A: Business Need

control logic implementation in the previous CANDU stations. The OH180 is used to control the majority of process systems (including special safety and safety related systems), electrical distribution system breakers and the Class 3 Transfer System. Each OH180 PK consists of several printed circuit boards (Central Processing Unit (CPU), Erasable Programmable Read Only Memory (EPROM) and, depending on the application, up to two power supplies, up to eight input and output boards and, in some cases, communications modules.

There are 1,344 OH180 programmable controllers currently installed at Darlington Nuclear Generating Station, consisting of over 12,000 printed circuit boards. Although the OH180s still operate quite reliably, the circuit boards are over 25 years old and are not expected to last until the extended end of station life. It is anticipated that the failure rate of the legacy OH180 boards will increase in the near future due to aging electronic components.

The existing hardware has been reverse engineered under Project#34011, so that replacement boards can be manufactured and spare parts procured. Investment in proactive replacement of OH180 hardware needs to be undertaken as all boards are not expected to last until end of station life, and will place a significant burden on operation and maintenance resources due to OH180 board failures. Some of the PKs are deemed Single Point Vulnerability (SPVs) and failure can result in a forced outage.

Part B: Preferred Alternative: Install Re-engineered OH180 Hardware Components

Description of Preferred Alternative

The preferred alternative is to complete proactive replacement of the following OH180 hardware components that are susceptible to failure due to aging:-

- Procure and install re-engineered OH180 Power Supplies (1,930)
- Procure and install re-engineered Communication Module Power Supplies (431)
- Procure and install re-engineered Communication Module Fibre Optic Transceiver boards (862)
- Procure and install re-engineered Input Boards (2,493)
- Procure and install re-engineered Output Boards (3,787)
- Upgrade EPROMs the OH180 executive program from version 112 of the OH180 executive program to version 117 for all OH180s in the plant as required (note: a number of OH180s have already been upgraded to version 117).
- Verify the existing OH180 database, so that it may be used as an approved tool to facilitate the preparation of commissioning plans for ladder logic changes

The previous release of this project completed the following work:-

1. Non-Identical Component Replacements or NICR EC packages for PK/Communication Module Power Supply Boards, and Item Equivalency Evaluation or IEE for the Input/output boards
2. Installation planning contract by external vendor to complete
   a) A comprehensive review of system condition requirements for each OH180 replacement to enable creation of a high level project schedule. Preliminary findings of this review indicate that approximately 632 PKs can be replaced with the unit under normal operating conditions (i.e. Online), 602 PKs require a Unit shutdown (i.e. Outage) and 108 PKs that require four unit shutdown (i.e Vacuum Building Outage or VBO). For this reason the project schedule has extended into 2027 when the next station VBO is planned. The project will review/challenge the number of PKs, that require outage or VBO replacement, during detailed planning (this release) and attempt to schedule these for Online replacements to reduce outage scope.
   b) Future releases of the BCS would allow creation of workplans to complete replacement of PKs under this contract

Due to the variation in complexity of this project and the large quantity of controllers in the plant, a pilot phase consisting of 3% PK replacement is planned in this Definition release. The purpose of the pilot execution is to complete hardware replacements on a varied selection of high/medium/low complexity PKs to obtain lessons learned and operating experience (OPEX), which will be used to refine the work planning/assessing for future PK replacements, and cost/schedule estimate for future execution releases. The scope of the pilot is strictly a maintenance type activity (replacement with equivalent components), and does not constitute a modification of the system or equipment function. If the installation were to be unsuccessful, the old components

Part B: Preferred Alternative: Install Re-engineered OH180 Hardware Components

Description of Preferred Alternative

can be reinstalled to return the equipment to its original condition. Therefore, the risk associated with the pilot is minimal.

The list of PKs selected for this pilot phase execution is included in the Appendix C of this document.

Deliverables:	Associated Milestones (if any):	Target Date:
Current Release		
Work Planning and Assessing Ready for 2017 Online Scope (Pilot Execution)	SOI - 2017 Online Scope (Pilot)	30- Jun-2017
Work planning and Assessing Complete for 2018 Online and Outage (D1831) Scope		02-Jan-2018
Materials staged for Online 2017 scope		1-Jun-2017
Complete pilot installations in 2017 and Available for Service (AFS)	AFS – 2017 Online Scope (Pilot)	29-Dec-2017
Execution Partial (Gate 3A) Business Case Summary	Execution Partial (Gate 3A) BCS Approved	29-Mar-2018
Future Releases		
Start of Installation for D1831 Outage	SOI – D1831 Outage Scope	30-Apr-2018
AFS of Installation of D1831 Outage	AFS – D1831 Outage Scope	30-Jun-2018
Start of Installation – 2018 - 2020 Scope	Start of Installation – 2018 Online Scope	30- Apr -2018
AFS Gate 3A - 2018 – 2020 Scope	AFS – 2018 Online Scope	31-Jan-2019
Execution Partial (Gate 3B) Business Case Summary	Execution Partial (Gate 3B) BCS Approved	31-Dec-2020
Execution Full (Gate 3C) Business Case Summary	Execution Partial (Gate 3C) BCS Approved	31-Dec-2023
All PK Replacements complete	Final AFS	31-Dec-2027
Project Complete	PCM - Project Complete	30-Jun-2028

Part C: Other Alternatives

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

Alternative 2: Base Case – No Project

This option entails replacement of OH180 boards upon failure, and not proactive replacement. Project#34011 has completed re-engineering of the OH180 boards and will stock 10% lifetime spares to replace components as they fail. This option is not recommended since all OH180 boards, selected for proactive replacement per the OH180 aging management study, are expected to eventually fail prior to station end of life, and threatens safe plant operation due to failure of vital control/monitoring equipment.

Pros:

- No upfront cost for proactive aging management replacement

Cons:

- As the OH180s continue to age, the failure rate will continue to increase exponentially as the population of OH180s enter the wear-out region of electronics reliability curve [R-1]. The burden on maintenance would become too large to keep up with the repairs as maintenance only has so many refreshed boards ready for replacement at a time.
- Waiting for a field failure to occur brings down the OH180 and the associated controlled system in an unplanned manner, thus creating a large burden on Operations and Maintenance.
- This alternative would result in unreliable operation of the OH180s which has the potential to impact safety and production as the OH180s control the majority of process systems including special safety and safety related systems. If multiple OH180 failures were to occur during a shift, Operations and Maintenance may not have the resources

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Project Title: OH180 Aging Management Hardware Installation, <Full> <Definition> Release

Alternative 2: Base Case – No Project

available to make the repairs and might be forced to shut down the Unit.

- System health will decline as components will not be replaced until they fail. There are not likely to be enough spares on hand to support the expected failure rate.

[R-1] *Evaluating the Effects of Aging on Electronic Instrument and Control Circuit Boards and Components in Nuclear Power Plants*. EPRI, Palo Alto, CA: May 2005. 1011709.

Alternative 3: Replace The OH180 System With An Off The Shelf Programmable Controller

Investigation into off-the-shelf technology indicates that there is nothing on the market that is a direct replacement. Adapting one of these systems would require:

- Extensive re-wiring of the station
- Re-qualification of the hardware and software
- Re-programming of the control logic for each of the process systems with a possibly new programming language and the resulting need for testing.
- Re-commissioning each system in which an OH180 was replaced
- Re-training of staff
- This alternative would be expensive and require long unit outages to implement. Furthermore, the new PLCs would not have the field diagnostic capabilities (ground fault detection, open wiring etc.) of the present OH180 system.

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

k$	LTD	2016	2017	2018	2019	2020	2021	Future	Total
Currently Released	295	478	625	-	-	-	-	-	1,398
Requested Now	-	-	4,863	1,029	-	-	-	-	5,892
Future Required	-	-	-	7,469	9,115	7,973	8,049	50,136	82,742
Total Project Cost	295	478	5488	8,498	9,115	7,973	8,049	50,136	90,032
Ongoing Costs	-	-	-	-	-	-	-	-	-
Grand Total	295	478	5488	8,498	9,115	7,973	8,049	50,136	90,032

Estimate Class:	Class 4	**Estimate at Completion:**	[redacted]
NPV:	Not Required (Sustaining Investment)	**OAR Approval Amount:**	$ 7,290k

Additional Information on Project Cash Flows (optional):

[redacted] contingency is included in the currently released, [redacted] of contingency is included in this requested release; [redacted] contingency is included in future releases.

Cash flow forecast based on high level PK replacement schedule assuming work Online, Unit Outages (non-Refurbishment) and VBO2027

Part E: Financial Evaluation

k$	Preferred Alternative	Base Case			
Project Cost	90,032				
NPV	N/A				
Other (e.g., IRR)					

Summary of Financial Model Key Assumptions or Key Findings:

Financial evaluation not required as this is a Sustaining investment.

Type 2 Business Case Summary

Project #: 16-80022
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Project Title: OH180 Aging Management Hardware Installation, <Full> <Definition> Release

Part F: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation	
			Probability	Impact
Cost	There is a risk that the cost of materials and labour will increase beyond the estimate between the start and end of the execution phase, as a result of an increase in the cost of raw materials and labour rates. There could be unexpected increases over the 10 year span of execution.	The risk of emergent cost escalation cannot be mitigated at this time. Sufficient contingency has been allocated to deal with this risk.	Medium	Medium
Cost	There is risk that the Operator and Maintainer field effort required for aligning the controllers to the conditions required for shutdown and board replacement is significantly greater than estimated, because work planning is not complete at this time. Each controller has not been assessed, and installation instructions have not been written for the replacement work. Execution could take longer than planned; project completion delayed. Cost could be greater than estimated.	This risk will be mitigated partly by completion of definition phase (work planning and assessing). To mitigate the remaining risk, the project will conduct a pilot installation of approximately 40 PKs (3%) to evaluate the effort required for the execution phase. The lessons learned from the pilot will be incorporated into the work planning, work assessing, and cost estimate for the execution phase.	Medium	Medium
Scope	There is a risk of discovering legacy configuration management and or programmatic issues. The effort required to correct legacy issues could result in significant project scope increase due to the large number of controllers.	There is no practical method to identify potential issues at this time. The issues will be addressed upon discovery. Sufficient contingency has been allocated to deal with this risk.	Low	Medium
Schedule	There is a risk that installation of some controllers cannot be executed as scheduled. The causes could be misunderstanding of equipment shutdown requirements; equipment outage consequences not considered; operator not comfortable with taking the equipment out of service at the scheduled time; emergent issues prevent the equipment from being removed from service; and/or scheduled outage windows shift. Failure to complete outage work could prolong the project duration beyond 2027, due to the three year outage cycle.	The project has contracted former maintainers and licensed operators to develop the installation strategy. The usage of this expertise will minimize the risk of PKs being classified incorrectly as online or outage. The project is also planning the installation to align with known unit outages, functional equipment group outages, and maintenance work. Finally, the project will continuously review the installation schedule with work control to identify conflicts that can prevent installation from being performed as scheduled and to identify opportunities to recover and improve the schedule.	High	Medium
Resources	There is a risk that Assessing, Operations and Maintenance resources are not available to perform installation and prerequisites, due to emergent work and or competing priorities. The impact would be delay to the installations and extension of project schedule. Outage prerequisites (milestones) could be missed.	The project has obtained commitments from Maintenance to provide qualified resources (either regular staff or temporary staff). The project will work with the Assessing and Work Plan Reviewer organization (s) to secure resources to support this project. Similarly, the project will present the execution plan to Operations, and obtain resource commitments prior to finalizing the execution schedule.	Medium	Low

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Part F: Risk Assessment				
Risk Class	**Description of Risk**	**Risk Management Strategy**	**Post-Mitigation**	
Resources	There is a risk of a shortage or unavailability of new boards to meet the installation schedule, due to obsolescence of raw materials and or suppliers going out of business over the 10 year span of execution. Impacts include delay to installation schedule and cost increase.	The supplier will implement a materials management strategy to minimize the risk of materials shortages for the total production quantity of new boards. The board design uses basic electronic parts; therefore, if materials do become obsolete, then substitutes can be used with minimal engineering effort. OPG owns the intellectual property rights for the new boards. If manufacturers go out of business, OPG will be able to contract the manufacturing to others. Also, as part of Project#34011, 10% lifetime spares would be ordered at the beginning of project (i.e. 2016/2017), hence sufficient spares would be on hand to deal with any board failures.	Low	Low
Technical/ Operation	There is a risk that the new boards respond unexpectedly after they are installed and put into service, due to design flaw that was not caught in design reviews, testing, and commissioning. Potential consequences range from unexpected individual equipment response to unit trip, depending on the impacted equipment/system.	The new boards have been designed, manufactured and tested to the extent possible under appropriate quality assurance programs. To mitigate this risk, the project will install the new boards in less critical systems at the start of the execution. This will allow the new boards to be evaluated in an in-service condition while minimizing the impact of any failures.	Low	Low
Technical/ Operation	There is a risk of discovering field conditions that do not match design documentation, including hardware configuration and differences between the ladder logic loaded in to the controller and the OH180 database. There is also risk that equipment may fail to start when the controller is returned to service, due to deteriorated and aging components. The impact ranges from minor delay to significant delay for equipment return to service.	There is no practical way to verify software configuration management prior to installation. There is also no practical method to identify degraded equipment. These risks cannot be mitigated at this time, and contingency has been allocated to respond to this risk if realized.	Medium	Low
Quality	There is a risk that the new boards may fail prematurely after they are installed and placed into service, as a result of material and or manufacturing defects. Most significant impact would be schedule delay.	The new boards have been designed, manufactured and tested to the extent possible under appropriate quality assurance programs. This risk cannot be mitigated any further prior to installation. The project will start the installation on lesser critical controllers. The old boards removed during the replacements will be salvaged and stored until the new boards have demonstrated adequate level of confidence. This will allow the controllers to be returned to service if the new boards experience problems.	Low	Low

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Part G: Post Implementation Review (PIR) Plan

☐ It is determined appropriate that only a Project Closure Report (PCR) is needed as the PIR for this project, due to its straight forward deliverables, which do not require any measures other than confirmation of completion or delivery.

Type of PIR Report	Target In-Service or Completion Date	Target PIR Completion Date
Comprehensive PIR	Q4, 2027	Q2, 2028

Measurable Parameter	Current Baseline	Target Result	How will it be measured?	Who will measure it? (person/group)
OH180 Hardware Replacement	Legacy boards in service	All boards identified for proactive replacement, replaced with new re-engineered boards	OH180 Configuration Tracking Database	Computers and Control Design Engineering
OH180 Failure Rate	0.025 failures per device year	Less than 0.025 failures per device year	Trending of failures and through the OH180 Programmable Controller Health Report	Computers and Control Design Engineering

Approvals

	Signature	Comments	Date
The recommended alternative, including the identified ongoing costs, if any, represents the best option to meet the validated business need.			
Recommended by (Project Sponsor): Rick Hohendorf Director Components Engineering			Jan. 6, 2017
I concur with the business decision as documented in this BCS.			
Finance Approval: George Turner Director, Controllership per OPG-STD-0076			JAN 10/2017
I confirm that this project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money.			
Approved by: Brian Duncan Senior Vice President, Darlington Nuclear per OAR 1.1	JAL 01-12-17	None	JAN 13/2017

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Appendix A: Summary of Estimate										
Project Number:	16-80022									
Project Title:	OH180 Aging Management Hardware Installation									
k$	**LTD**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Future**	**Total**	**%**
OPG Project Management	97	106	366	162	184	224	174	965	2,278	3
OPG Engineering (including Design)	61	-	48	134	156	157	141	1,241	1,937	2
OPG Procured Materials	-	-	1,803	2,793	2,344	1,843	2,537	13,029	24,349	27
OPG Other	-	-	266	78	91	76	59	505	1,075	1
Design Contract(s)	[redacted]									
OPG Installation	-	-	116	426	659	714	208	2,653	4,776	5
EPC Contract(s)	[redacted]									
Consultants										
Other Contracts/Costs										
Interest										
Subtotal										
Contingency										
Total	**295**	**478**	**5,134**	**8,962**	**9,059**	**7,925**	**7,998**	**50,180**	**90,032**	**100%**

Notes			
Project Start Date	2014-12-15	**Total Definition cost** (excludes unspent contingency for Nuclear)	[redacted]
Target In-Service (or AFS) Date	2027-12-31	**Contingency included in this BCS** (Nuclear only)	
Target Completion Date	2028-06-30	**Total contingency released plus contingency in this BCS** (Nuclear only)	
Escalation Rate	2.0%	**Total released plus this BCS without contingency** (Nuclear only)	
Interest Rate	5.5%	**Total released plus this BCS with contingency** (Nuclear only)	$7,290 k
Removal Costs	$115k	**Estimate at Completion** (includes only spent contingency for Nuclear)	[redacted]

Prepared by:		Approved by:	
US	22 Dec 2016		04 Jan 2017
Usman Siddiqi Technical Engineer/Officer Projects & Modifications	Date	Mike Nairne Section Manager Projects & Modifications	Date

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

Comparison of Total Project Estimates

Phase	Release	Approval Date	Total Project Estimate in k$ (by year including contingency)						Future	Total Project Estimate
			LTD 2015	2016	2017	2018	2019	2020		
Definition	Full	Nov 2014	1357	2,562	7,301	7,454	7,179	-	21,350	47,203
Definition	Full	Dec 2016	295	478	5488	8,498	9,115	7,973	58,185	90,032

Project Variance Analysis

k$	LTD	Total Project		Variance	Comments
		Last BCS	This BCS		
OPG Project Management	203	2,295	2,278	(17)	
OPG Engineering (including Design)	61	5,698	1,937	(3,761)	Engineering effort reduced as the Installation planning (Workplans) is being contracted to external vendor. Transferred to 'Other Contracts'
OPG Procured Materials	-	22,620	24,349	1,729	Added materials for 832 Communication Module Fibre Optic Boards, and new estimate received from OEM
OPG Other		9	1,075	1,066	This is to incorporate cost of WO Assessing and Workplan Reviews (Ops/Maintenance etc). Part of this cost was carried under 'OPG Engineering' previously.
Design Contract(s)	[redacted]				
OPG Installation	-	0	4,776	4,776	Installation to be completed by OPG Ops/Maintenance resources
EPC Contract(s)	[redacted]				
Consultants					
Other Contracts/Costs					
Interest					
Subtotal					
Contingency					
Total	**612**	**47,203**	**90,032**	**42,829**	

Appendix C: List of 40 OH180 Controllers selected for 3% replacement under this release

The OH180 Programmable Controllers control various systems around the station, hence presents a wide degree of complexity in ability to remove each PK from service for replacement of hardware components. Due to this reason, a good estimate is difficult to obtain. The purpose of the pilot phase execution during 2017 (approximately 40 PKs or 3% of total scope) is to perform hardware replacements on a representative sampling of PKs to obtain lessons learned (OPEX), and cost/schedule estimate for the project Execution release. The following list details the list of PKs selected for this pilot execution, along with justification.

Unit				SCI	Device	Complexity (High/ Medium/ Low)	Criticality Level (1/2/3/4)	Half Rack or Full Rack	Fibre-optic Loop (CM)	EPROM Upgrade Required (Y/N)	Comments for addition to 3% Pilot Phase
0	1	3	4								
	x	x		67210	PK0001-11	Low	3	Half Rack	N	Y/N	Ability to execute work by aligning scheduled work on same system. Observation of completing work with reduced redundacy.
		x		63660	PK0012-11	Low	3	Half Rack	N	Y	Low risk equipment to establish comfort level with replacements, and rountine system alignments performed via WOTIs.
	x	x		67230	PK0013-11	Low	3	Half Rack	N	N	Observations for replacing safety system replaced PKs of low complexity. Ability to execute work by aligning with FEG Work Week.
	x		x	63341	PK0014-11	Medium	1	Half Rack	N	N	Executing a work plan for medium complexity PKs, use findings to determine applicability of WOTI for medium complexity work.
	x	x		64830	PK0077-11	Low	3	Full Rack	N	Y/N	Observations from replacing a PK with multiple controlled components, other than pumps and valves.
	x		x	67210	PK0157-11	Low	3	Full Rack	N	Y/N	Observations from replacing a PK with multiple controlled components.
	x	x		65330	PK0193-11	Low	3	Full Rack	N	N	Simple full rack PK, to establish comfort level with replacements of multiple boards and power supplies.
	x		x	67230	PK0313-21	Low	3	Half Rack	N	N	Observation of replacing EVEN PK, and comparing responses to ODD PK replacement findings.
	x	x	x	63341	PK0314-21	Medium	1	Half Rack	N	N	Observation of using a work plan for replacing EVEN PK, and comparing responses to ODD PK replacement findings.
		x		63617	PK0327-21	High	3	Full Rack	N	N	Establish a comfort level in executing work plans for high complexity PKs. Completing replacement on a system requiring specific unit alignments on major equipment.
	x		x	67210	PK0409-21	Low	3	Full Rack	N	Y	Ability to execute work by aligning with FEG Work Week. Observation of completing work with reduced redundacy
		x	x	65330	PK0483-21	Low	3	Full Rack	N	N	Low complexity replacement to establish comfort level with replacements of full rack PK
		x		65330	PK0485-21	Low	3	Full Rack	N	N	Low complexity replacement to establish comfort level with replacements of full rack PK
		x		64300	PK0489-21	High	2	Full Rack	N	N	Establish a comfort level in executing work plans on a safety system for high complexity PKs. Completing replacement on a system requiring specific unit alignments on multiple components.

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Unit				SCI	Device	Complexity (High/ Medium/ Low)	Criticality Level (1/2/3/4)	Half Rack or Full Rack	Fibre-optic Loop (CM)	EPROM Upgrade Required (Y/N)	Comments for addition to 3% Pilot Phase
0	1	3	4								
	x	x	x	67390	PK0761-21	High	3	Half Rack	FOL 0040	Y/N	Ability to execute similar work plan across different units, expecting same result. Observation of fiber-optic loop response across each unit.
x				65330	PK1001-11	Low	3	Full Rack	N	N	Multiple PKs associated with annunciation only responses. To establish comfort level with replacements of full rack PK
x				65330	PK1003-11	Low	3	Full Rack	N	N	Multiple PKs associated with annunciation only responses. To establish comfort level with replacements of full rack PK
x				67210	PK1007-11	Low	3	Half Rack	N	Y	Unit 0 PK associated with a Unitized PK replacement to see if any differences in replacement in field.
x				63426	PK1069-N1	Low	3	Full Rack	FOL 0012	Y	Addresses a PK that affects multiple units, and is a monitoring PK in the fiber-optic loop. Will require operations cooridination to communicate annunciation acknowledgment.
x				67210	PK1111-21	Low	3	Half Rack	N	Y	Unit 0 PK associated with a Unitized PK replacement to see if any differences in replacement in field.
x				63432	PK1133-21	Medium	3	Full Rack	FOL0019	N	This is a monitoring PK, and observations can be made to the predicted reaction from other CMs in the firber-optic loop. Multiple PKs are associated with this PK.
		x		63432	PK2001-52	Medium	4	Half Rack	FOL0042	N	Will provide OPEX to be used for completing ECI non-test PKs. Multiple PKs are associated with ECI testing logic, where replacement will provide insight of system response, and scope of like-replacements.
		x		63432	PK2015-K2	Medium	4	Half Rack	FOL0041	N	Will provide OPEX to be used for completing ECI non-test PKs. Multiple PKs are associated with ECI channel test logic, where replacement will provide insight of system response, and scope of like-replacements.
x				67280	PK2431-62	High	3	Full Rack	FOL0048	N	Ability to execute work complex work online. Obseravtion of PK response due to multiple scans required.
		x	x	60311	PK3107-11	Low	3	Half Rack	N	Y/N	Multiple PKs associated with annunciation responses. PK without defined criticality from SRE, replacement provides required info to make this determination.
x				65855	PK3364-21	High	3	Half Rack	N	N	Many PKs are associated with Class 3 bus work. Ability to align this type of work with planned SRSTs can help determine the readiness for performing more bus work online.

UNDERTAKING J15.6

Undertaking

For the Chiller Replacement to Reduce CFC Emissions, to provide when the project was substantially completed and the capital was placed into service.

Response

This undertaking is by reference to cross-examination by AMPCO related to a table that purported to derive variances from a original project targeted in-service date to final in service date (K15.1, pages 32-34).

The DN Chiller Replacement project was substantially complete on January 23, 2013, with 92% of capital project cost ($20.2M) declared in-service. Key milestone dates as well as dates of in-service declarations for when the capital was placed into service for this project are set out in Attachment C to the Business Case Summary found at Ex. D2-1-3 Attachment 1, Tab 6. As shown in Attachment C, in-service amounts were spread out over 3 years tied to the installation schedule. The remaining 8% was not declared in service despite all hardware being installed and the project used and useful, while close out work is being undertaken to address low load vibration.

Part of the increase in the project's cost estimate from $14.9M to $30.0M was driven by the schedule delays discussed above The cost increase also resulted from experience gained from installations of the first two units, which proved more complex than initially planned as well as a change in installation strategy to ensure sufficient cooling during the chiller replacement period. The $30M Class 1 cost estimate reflected in the Full Release BCS (Ex. D2-1-3 Attachment 1, Tab 6) was a direct result of lessons learned and actual cost information associated with the installation of the initial chillers. The $14.9M cost estimate in the Phase 1 BCS was established before the design was complete.

UNDERTAKING J15.7

Undertaking

To provide which of the Tier 1 Business Case Summaries referred to at Attachment 1 of L-4.2-AMPCO-17 have gone through the revised gated process.

Response

The following four Tier 1 Business Case Summaries referred to at Attachment 1 of L-4.2-AMPCO-17 have gone through the revised gated process:

- 31710 - DN Shutdown Cooling Heat Exchanger Replacement
- 31508, 49158, 49299 - Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment
- 41027 32202 - Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment
- 73566, 80144 - Primary Heat Transport Pump Motor Replacement/Overhaul

UNDERTAKING J15.8

Undertaking

Where available, provide the past five years' historical SPI and CPI values for the Projects and Modifications' portfolio (at the aggregate level), as well as any forecast SPI and CPI.

Response

Table 1 below provides historical SPI and CPI values for the period 2012 to 2016. An index score greater than 1.0 indicates performance better than target while less than 1.0 represents a score worse than target. As noted at Tr. Vol. 15, p. 63, OPG does not forecast SPI and CPI.

Table 1

Project & Modifications SPI, CPI 2012-2016

	Target	2012	2013	2014	2015	2016
Cost Performance Index (CPI)	1.00	1.05	1.02	0.99	1.01	1.03
Schedule Performance Index (SPI)	1.00	0.95	0.87	0.85	0.81	0.85

UNDERTAKING J15.9

Undertaking

To confirm the date the Fuel Channel Life Management project was completed and the final cost for the project.

Response

The Fuel Channel Life Management project was completed in June 2016. The final cost for the project was $49.5M.

UNDERTAKING J15.10

Undertaking

To provide what the net impact on the forecast nuclear production would be in the case of a 12-month and 18-month delay on the Darlington Refurbishment Program.

Response

In order to respond to this undertaking, OPG has adhered to the assumptions requested, but OPG does not view these assumptions as reasonable. As noted in Ex. L-4.3-7 ED-004, OPG has learned significantly from the experiences of past large complex projects and has executed a robust planning process. The Release Quality Estimate (RQE) and schedule produced in 2015 is a high confidence cost and schedule estimate, including contingencies.

While there will be risks associated with the execution of the DRP, OPG as the general contractor will play an active role in monitoring the work and ensuring that all risks are actively managed. OPG would intervene and take appropriate actions to mitigate the schedule impacts long before the circumstances contemplated in this undertaking. The contractors are responsible and have incentives to mitigate and recover schedule delays. There are also off-ramps in the contracts that allow OPG to terminate contracts in situations where performance is not meeting expectations. OPG has full transparency on the status of the overall DRP, in terms of safety, quality, schedule, and cost performance, and would take corrective actions very early in the process, as required.

Chart 1 summarizes the hypothetical impact on the nuclear production forecast of delays to the in-service date of Darlington Unit 2. The assumptions used to estimate these impacts, which would be subject to change based on the actual drivers to a Unit 2 in-service delay, are provided below.

Chart 1

	6-month Delay	12-month Delay	18-month Delay
Net Impact of Delay on Production Forecast	Gain of 0.6 TWh (assuming no delay to start of Unit 1 refurbishment per Ex. L-5.1-15 SEC-049) Gain of 4.5 TWh (assuming a 6-month delay to start of Unit 1 refurbishment as described below)	Gain of 1.0 TWh	Loss of 1.8 TWh

In all scenarios, it is assumed that there would be no impact on the production forecast in 2017, 2018 or 2019.

In the 6-month delay scenario (Ex. L-5.1-15 SEC-049), OPG had assumed that the start of Unit 3 could be delayed by 6 months (to mid-August 2020). However, in the 12-month and 18-month delay scenarios, OPG has assumed that Unit 3 would be idled from mid-August 2020 onwards, consistent with the current end-of-life date for Unit 3 being early to mid-2020 (see Ex. L-4.3-8 GEC-009).

In the 6-month delay scenario (Ex. L-5.15-15 SEC-049), OPG had assumed no change in the start date for Unit 1. However, had Unit 1 refurbishment been assumed to be delayed by six months to December 2021, there would have been a gain of 183 days, representing about 3.9 TWh in addition to the 0.6 TWh identified in Ex. L-5.1-15 SEC-049. Under the 12-month and 18-month delay scenarios, the start date of Unit 1 refurbishment (currently June 2021) is assumed to be pushed to outside the rate period.

Based on the above assumptions, a 12-month delay would result in the following:

2020:

- For Unit 2, a loss of 10.5 months production from mid-Feb 2020 to end of 2020; slightly off-set by the first mini post commissioning outage for Unit 2 of 55 days being delayed from fall 2020 to fall 2021.
- For Unit 3, a gain in production compared to the base case of 6 months from February 15, 2020 to August 15, 2020, then Unit 3 being idled from August 15, 2020 to the end of 2020.
- For Units 1 & 4, no production impacts.

2021

- For Unit 2 there would be a loss of 1.5 months production from Jan 2021 to mid-Feb 2021, an outage days increase of 55 days for the first mini post commissioning outage shifting into 2021 and an outage days reduction for the second mini post commissioning outage of 31 days being delayed from fall 2021 to outside the rate period.
- For Unit 3, there would be no net change, as the Unit would have been on refurbishment for all of 2021. In this scenario, the refurbishment of Unit 3 is assumed to start on February 15, 2021.
- For Unit 1, the shift of Unit 1 refurbishment to outside the rate period would be a gain of production of 200 days in 2021.
- For Unit 4, there would be no production impacts.

Based on the above assumptions, an 18-month delay would result in the following:

2020:

- Production impacts are identical to the 12-month delay scenario.

2021

- For Unit 2 there would be a loss of 7.5 months production from Jan 2021 to mid-August 2021, and an outage days decrease of 55 days plus 31 days for both the first and second mini post commissioning outages shifting to outside the rate period.
- For Unit 3, there would be no net change, as the Unit would have been on refurbishment for all of 2021. In this scenario, the refurbishment of Unit 3 is assumed to start on August 15, 2021.
- For Unit 1, the shift of Unit 1 refurbishment to outside the rate period would be a gain of production of 200 days in 2021.
- For Unit 4, there would be no production impacts in the rate period.

UNDERTAKING J15.11

Undertaking

To update Ex. E2-1-2, Table 1 (Comparison of Production Forecast – Nuclear) for 2016 actuals.

Response

An update of Ex. E2-1-2, Table 1 to include 2016 actual production values is provided in Attachment 1.

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Update to E2-1-2 Table 1
Comparison of Production Forecast - Nuclear

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved[2]	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	**TWh**	26.9	(1.8)	25.1	2.9	27.1	0.9	28.0	(4.7)	25.0	(1.7)	23.3
2	**Unit Capability Factor (%)**	88.8	(5.9)	82.9	9.0	93.5	(1.6)	91.9	(15.0)	86.3	(9.4)	76.9
3	**PO Days**	144.4	0.1	144.5	(52.4)	77.1	15.0	92.1	174.8	188.0	78.9	266.9
4	**FEPO Days**	0.0	39.8	39.8	(39.8)	0.0	0.0	0.0	7.7	0.0	7.7	7.7
5	**FLR (%)**	1.5	3.3	4.8	(3.3)	1.3	0.3	1.5	3.4	1.0	3.9	4.9
6	**FLR Days Equivalent**	19.7	41.8	61.5	(41.0)	14.6	5.9	20.5	36.9	12.7	44.7	57.4
	Pickering NGS											
7	**TWh**	21.1	(1.5)	19.6	0.5	21.9	(1.8)	20.1	1.1	21.6	(0.4)	21.2
8	**Unit Capability Factor (%)**	79.2	(5.5)	73.7	1.6	79.9	(4.6)	75.3	4.1	82.1	(2.8)	79.4
9	**PO Days**	303.5	(82.7)	220.8	64.1	292.9	(8.0)	284.9	65.2	287.9	62.2	350.1
10	**FEPO Days**	0.0	167.6	167.6	(112.2)	0.0	55.4	55.4	(14.8)	0.0	40.6	40.6
11	**FLR (%)**	8.1	1.6	9.7	1.0	7.8	3.0	10.7	(7.8)	5.5	(2.6)	2.9
12	**FLR Days Equivalent**	152.4	21.4	173.8	24.2	147.0	51.0	198.0	(146.3)	104.5	(52.8)	51.7
	Totals											
13	**Unit Capability Factor (%)**	84.3	(5.7)	78.6	5.7	87.6	(3.3)	84.3	(6.3)	84.0	(6.0)	78.0
14	**PO Days**	447.9	(82.6)	365.3	11.7	370.0	7.0	377.0	239.9	475.9	141.0	616.9
15	**FEPO Days**	0.0	207.4	207.4	(152.0)	0.0	55.4	55.4	(7.1)	0.0	48.3	48.3
16	**FLR (%)**	4.5	2.5	7.0	(1.5)	4.1	1.5	5.6	(1.6)	3.1	0.8	3.9
17	**FLR Days Equivalent**	172.1	63.2	235.3	(16.8)	161.6	56.9	218.5	(109.4)	117.2	(8.1)	109.1
18	**Total TWh**	48.0	(3.3)	44.7	3.4	49.0	(0.9)	48.1	(3.5)	46.6	(2.1)	44.5

Line No.	Business Unit	2015 Actual	(e)-(a) Change	2016 Budget	(c)-(e) Change	2016 Actual	(g)-(e) Change	2017 Plan	(i)-(g) Change	2018 Plan	(k)-(i) Change	2019 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
19	**TWh**	23.3	2.4	26.0	(0.4)	25.6	(6.6)	19.0	0.2	19.3	0.4	19.7
20	**Unit Capability Factor (%)**	76.9	12.6	91.1	(1.6)	89.5	(4.4)	85.1	0.9	86.0	1.7	87.8
21	**PO Days[3]**	266.9	(156.8)	111.0	(0.9)	110.1	43.3	153.4	(10.1)	143.3	(19.2)	124.1
22	**FEPO Days**	7.7	(7.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**FLR (%)**	4.9	(2.5)	1.0	1.3	2.3	(1.3)	1.0	(0.0)	1.0	0.0	1.0
24	**FLR Days Equivalent**	57.4	(27.6)	12.7	17.0	29.8	(20.4)	9.4	0.1	9.5	0.2	9.7
	Pickering NGS											
25	**TWh**	21.2	(1.3)	20.8	(0.9)	19.9	(0.9)	19.1	0.1	19.2	0.2	19.4
26	**Unit Capability Factor (%)**	79.4	(4.1)	77.6	(2.4)	75.2	(3.7)	71.5	0.5	72.0	0.6	72.6
27	**PO Days**	350.1	19.2	401.6	(32.3)	369.3	172.3	541.6	(10.8)	530.8	(13.7)	517.2
28	**FEPO Days**	40.6	52.9	0.0	93.5	93.5	(93.5)	0.0	0.0	0.0	0.0	0.0
29	**FLR (%)**	2.9	1.2	5.0	(0.9)	4.1	0.9	5.0	(0.0)	5.0	0.0	5.0
30	**FLR Days Equivalent**	51.7	18.5	89.7	(19.5)	70.2	12.2	82.4	0.5	83.0	0.7	83.6
	Totals											
31	**Unit Capability Factor (%)**	78.0	4.7	84.6	(2.0)	82.7	(4.9)	77.8	0.7	78.5	(39.5)	39.0
32	**PO Days[3]**	616.9	(137.5)	512.6	(33.2)	479.4	215.6	695.0	(20.8)	674.1	(32.9)	641.3
33	**FEPO Days**	48.3	45.2	0.0	93.5	93.5	(93.5)	0.0	0.0	0.0	0.0	0.0
34	**FLR (%)**	3.9	(0.8)	2.8	0.3	3.1	(0.1)	3.0	(0.0)	3.0	(0.0)	3.0
35	**FLR Days Equivalent**	109.1	(9.1)	102.4	(2.4)	100.0	(8.1)	91.8	0.6	92.5	0.9	93.4
36	**Total TWh**	44.5	1.0	46.8	(1.2)	45.6	(7.5)	38.1	0.4	38.5	0.6	39.0

Line No.	Business Unit	2019 Plan	(c)-(a) Change	2020 Plan	(e)-(c) Change	2021 Plan
		(a)	(b)	(c)	(d)	(e)
	Darlington NGS					
37	**TWh**	19.7	(1.9)	17.7	(1.1)	16.6
38	**Unit Capability Factor (%)**	87.8	(8.4)	79.4	11.5	90.9
39	**PO Days[3]**	124.1	64.1	188.2	(131.9)	56.2
40	**FEPO Days**	0.0	0.0	0.0	0.0	0.0
41	**FLR (%)**	1.0	3.2	4.2	(1.2)	3.0
42	**FLR Days Equivalent**	9.7	28.4	38.1	(13.1)	25.0
	Pickering NGS					
43	**TWh**	19.4	0.3	19.6	(0.8)	18.8
44	**Unit Capability Factor (%)**	72.6	0.8	73.4	(2.8)	70.6
45	**PO Days**	517.2	(18.3)	498.9	63.9	562.8
46	**FEPO Days**	0.0	0.0	0.0	0.0	0.0
47	**FLR (%)**	5.0	0.0	5.0	(0.0)	5.0
48	**FLR Days Equivalent**	83.6	1.2	84.9	(3.5)	81.4
	Totals					
49	**Unit Capability Factor (%)**	39.0	37.2	76.2	2.8	79.0
50	**PO Days[3]**	641.3	45.8	687.1	(68.1)	619.0
51	**FEPO Days**	0.0	0.0	0.0	0.0	0.0
52	**FLR (%)**	3.0	1.6	4.6	(0.6)	4.0
53	**FLR Days Equivalent**	93.4	29.6	122.9	(16.6)	106.3
54	**Total TWh**	39.0	(1.7)	37.4	(2.0)	35.4

Notes:
1 OEB Approved nuclear production in 2014 is 49.0 TWh per EB-2013-0321 Decision with Reasons p. 39.
2 OEB Approved nuclear production in 2015 is 46.6 TWh per EB-2013-0321 Decision with Reasons p. 39.
3 PO days excludes planned outage days for Darlington units out of service during Darlington refurbishment.

UNDERTAKING J15.12

Undertaking

To update the total overtime values in table in parts c and d of L-6.6-2 AMPCO-135 for the 2016 actuals.

Response

Total actual overtime values for 2016 have been provided in Table 1 below:

Table 1

Total Nuclear	Actual ($M) (a)	Budget ($M) (b)	Variance ($M) (c) = (a)-(b)	Variance (d) = (c)/(b)
2013	159.2	127.0	32.2	25.3%
2014	117.6	109.3	8.2	7.5%
2015	132.1	122.3	9.7	7.9%
2016	136.4	111.7	24.7	22.1%

Actual overtime in 2016 was higher relative to budget to address labour declines experienced as a result of greater than anticipated attrition and hiring lags. Consistent with OPG's response to J14.3 in respect of Base OM&A, overtime is one part of the mix of resources OPG uses to carry out its work requirements and the actual mix between types of labour and overtime can vary by year depending on work requirements and existing staff levels.

UNDERTAKING J15.13

Undertaking

Ref: L-5.1-5 CCC-24

Provide the updated revenue impact of the outage based on the Ex. N3-1-1 impact statement.

Response

Please see Attachment 1 to this undertaking response. Attachment 1 updates the Revenue Impact of Outage column from Ex. L-5.1-5 CCC-024 Attachment 1 based on the proposed nuclear payment amounts reflected in Ex. N3-1-1.

Please note that the formulas used to calculate total production and total revenue impacts for Darlington in 2020 were incorrect in Ex. L-5.1-5 CCC-024 and have been corrected in the updated table, consistent with Undertaking JT2.14. The corrected formulae result in total 2020 production increasing from 14.8TWh to 18.1TWh. To be clear, however, there is no change in total production impact in 2020 as a result of updating the table to reflect the nuclear payment amounts proposed in Ex. N3-1-1.

Year		Outage	Unit Affected	Description	Outage Duration (days)	Forecast Production (TWh) Impact Due to Outage	Revenue Impact of Outage ($M)
2017	Pickering	P1711	Unit 1	Planned Outage	204.9	2.6	195.0
		P1742	Unit 4	Mid-Cycle Outage	43.0	0.5	40.9
		P1751	Unit 5	Planned Outage	160.7	2.0	153.2
		P1761	Unit 6	Planned Outage	133.0	1.7	126.8
		Total			**541.6**	**6.8**	**515.9**
	Darlington	D1711	Unit 1	Planned Outage	108.4	2.3	177.5
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	597.6
		D1731-PD	Unit 3	Planned Derate	2.5	0.1	4.1
		D1732	Unit 3	PHT Pump Motor Outage	20.0	0.4	32.7
		D1741-PD	Unit 4	Planned Derate	2.5	0.1	4.1
		D1742	Unit 4	PHT Pump Motor Outage	20.0	0.4	32.7
		Total			**518.4**	**11.1**	**848.7**
Total 2017					**1,060.0**	**17.9**	**1,364.6**
2018	Pickering	P1812	Unit 1	Mid-Cycle Outage	43.0	0.5	42.1
		P1841	Unit 4	Planned Outage	144.1	1.8	141.1
		P1871	Unit 7	Planned Outage	193.5	2.4	189.8
		P1881	Unit 8	Planned Outage	150.2	1.9	147.3
		Total			**530.8**	**6.6**	**520.4**
	Darington	D1811	Unit 1	PHT Pump Motor Outage	20.0	0.4	33.7
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	614.9
		D1831	Unit 3	Planned Outage	103.3	2.2	174.0
		D1841	Unit 4	PHT Pump Motor Outage	20.0	0.4	33.7
		Total			**508.3**	**10.9**	**856.3**
Total 2018					**1,039.1**	**17.5**	**1,376.6**
2019	Pickering	P1911	Unit 1	Planned Outage	128.5	1.6	135.8
		P1942	Unit 4	Mid-Cycle Outage	43.0	0.5	45.4
		P1951	Unit 5	Planned Outage	165.6	2.1	175.3
		P1961	Unit 6	Planned Outage	180.1	2.2	190.7
		Total			**517.2**	**6.5**	**547.2**
	Darlington	D1911	Unit 1	PHT Pump Motor Outage	20.0	0.4	36.4
		D1912-PD	Unit 1	Planned Derate	2.5	0.1	4.5
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	663.6
		P1931-PD	Unit 3	Planned Derate	2.5	0.1	4.5
		D1941	Unit 4	Planned Outage	99.1	2.1	180.2
		Total			**489.1**	**10.5**	**889.2**
Total 2019					**1,006.3**	**16.9**	**1,436.4**
2020	Pickering	P2012	Unit 1	Mid-Cycle Outage	43.0	0.5	47.2
		P2041	Unit 4	Planned Outage	164.5	2.0	180.7
		P2071	Unit 7	Planned Outage	102.5	1.3	112.8
		P2081	Unit 8	Planned Outage	188.9	2.4	208.0
		Total			**498.9**	**6.2**	**548.8**
	Darlington	D2011	Unit 1	Planned Outage	108.2	2.3	204.6
		DNRU2	Unit 2	Refurbishment Outage	45.0	1.0	85.1
		D2022-PD	Unit 2	Planned Derate	2.5	0.1	4.7
		D2021	Unit 2	Post Refurb Mini Outage	55.0	1.2	104.0
		DNRU3	Unit 3	Refurbishment Outage	321.0	6.9	606.9
		D2042-PD	Unit 4	Planned Derate	2.5	0.1	4.7
		D2041	Unit 4	PHT Pump Motor Outage	20.0	0.4	37.8
		Total			**554.2**	**11.9**	**1047.7**
Total 2020					**1,053.1**	**18.1**	**1,596.5**
2021	Pickering	P2111	Unit 1	Planned Outage	150.5	1.9	172.5
		P2141	Unit 4	Vacuum Building Outage	30.0	0.4	34.4
		P2151	Unit 5	Planned Outage	179.7	2.2	206.4
		P2161	Unit 6	Planned Outage	112.6	1.4	129.3
		P2162	Unit 6	Vacuum Building Outage	30.0	0.4	34.5
		P2171	Unit 7	Vacuum Building Outage	30.0	0.4	34.5
		P2181	Unit 8	Vacuum Building Outage	30.0	0.4	34.5
		Total			**562.8**	**7.0**	**645.9**
	Darlington	DNRU1	Unit 1	Refurbishment Outage	200.0	4.3	394.4
		D2121	Unit 2	Post Refurb Mini Outage	31.2	0.7	61.5
		D2122-PD	Unit 2	Planned Derate	2.5	0.1	4.9
		DNRU3	Unit 3	Refurbishment Outage	365.0	7.8	719.8
		D2142-PD	Unit 4	Planned Derate	2.5	0.1	4.9
		D2141	Unit 4	PHT Pump Motor Outage	20.0	0.4	39.4
		Total			**621.2**	**13.3**	**1,225.1**
Total 2021					**1,184.0**	**20.3**	**1,871.0**

UNDERTAKING J15.14

Undertaking

To provide, out of those 85 former employees that were rehired, how many were simultaneously or concurrently retiring and being rehired in a very short period of time. OPG to quantify “short period of time” in its response.

Response

10 out of the 85 rehires referenced in L-6.6-2 AMPCO-140 retired and then were subsequently rehired in less than one month. 4 of the 10 individuals rehired in a short period of time are previously nuclear authorized operators and are in positions that require them to have been licensed.

UNDERTAKING J16.1

Undertaking

TO CONFIRM WHETHER PICKERING AND DARLINGTON HAVE ROUGHLY THE SAME NUMBER OF EMPLOYEES MANAGED BY THE SHIFT MANAGER.

Response

The structure, format, and scope of accountability are the same for the Shift Managers at Pickering and Darlington. Specific staff numbers will vary between shift crews with approximately 50 staff reporting directly to a Shift Manager at each of Pickering B and Darlington (4 unit stations), and 35 staff at Pickering A (2 unit station). The number of staff reporting to a Shift Manager at Pickering A as compared to Pickering B is not only tied to the difference in number of units, but also the additional responsibility of Pickering A staff for common systems that support both plants and surveillance of the shutdown units. This results in greater and more complex supervisory accountabilities for OPG Shift Managers in relation to comparable plants in other jurisdictions, where such oversight is limited to two operating units.

In addition to the above, and as noted at Tr. Vol. 16, p. 58, lines 18-28, and p. 59, lines 1-7, the CANDU technology at OPG's nuclear generating stations is more complex and has a greater number of integrated systems and components as compared to technologies used by comparators in other jurisdictions; for example, CANDU reactors have up to five times the number of components. As a result, nuclear authorized operators at OPG have greater responsibilities and complexities in their role. For the CANDU one OPG authorized nuclear operator monitors or operates: (i) the computer control systems that regulate and integrate the reactors with the entire plant, and (ii) the on power refueling systems. For the comparator technology, 3 operators - a Senior Reactor Operator and two panel operators, are required to carry out a less complex role. The additional complexity associated with CANDU reactors is also reflected in the training requirements for authorized operations staff. CANDU authorized operators typically require up to 36 months training, as compared to other technology comparators where the training program is between 14 to 16 months.

UNDERTAKING J16.2

Undertaking

To advise the jobs within the "General Industry" that were not part of the benchmark.

Response

In the compensation benchmarking study found at Ex. F4-3-1, Attachment 2, Willis Towers Watson (WTW) was able to match 66% of the General Industry segment of OPG's population. According to WTW, this represents a strong level of representation of disciplines and levels across the General Industry segment. The purpose of benchmarking is to select an appropriate sample of jobs that create "apples to apples" comparisons of similar jobs across organizations. As noted in L-6.6-1 Staff-149 (b), compared to the previous benchmarking conducted by Aon Hewitt, the WTW benchmarking was able to benchmark more OPG positions and more appropriately match positions in the General Industry segment (see EB-2013-0321, Ex. F5-4-1).

Figure 1 below provides a listing of the jobs within the General Industry segment with more than 10 incumbents that were not included in the WTW compensation benchmarking study found at Ex. F4-3-1, Attachment 2. As noted in Ex. JX17.9, OPG is not permitted to release security protected prescribed information, including the number of security staff at OPG's nuclear facilities, pursuant to sections 21 (1) (c) and 23 (1) of the General Nuclear Safety and Control Regulations under the *Nuclear Safety and Control Act*. For this reason, such staff was excluded from the WTW benchmarking. Nuclear security staff make up the majority of excluded incumbents from the General Industry segment.

Figure 1 - Unmatched Jobs in the General Industry Category with More Than 10 Incumbents

PWU	Society	Management
Analyst/Buyer	Assistant Procurement Specialist	*none*
Nucl Security Officer ***(EXCLUDED)***	Cost and Schedule Analyst	
Nucl Security Officer FLMa ***(EXCLUDED)***	Financial Analyst (MP3 only)	
Plant Production Clerk	FLM, Civil Maintenance	
	Security FLM	

For benchmarking purposes, jobs are matched by discipline and career level, and consider the scope of duties involved in order to ensure a fair comparison. Participating organizations may employ individuals in a similar discipline to OPG employees, but these individuals may have different duties or may not be at the same level of accountability as the OPG employees. Unique or multi-discipline roles are typically excluded from benchmarking studies as suitable matches cannot be found for these positions. For example, OPG's Cost and Schedule Analysts perform a number of duties that would be commonly found in jobs in the finance function, including monitoring and analyzing costs and supporting the preparation of budgets. They also perform a number of duties not commonly found finance jobs, including analyzing work program performance, supporting the preparation of project execution plans and monitoring schedule performance. These additional duties are more commonly found in programming and project management related jobs that are part of the utility segment. Accordingly, given the substantially broader duties associated with OPG's Cost and Schedule Analysts relative to similar jobs in the General Industry, a suitable match for OPG's Cost and schedule Analysts could not be identified, and these positions were not matched in the benchmarking analysis results.

In addition, participating organizations may not submit information for some jobs, either because they chose not to, they do not have such jobs, or they do not have such jobs that involve the same level of accountability as OPG. For example, organizations who outsource certain functions in the General Industry segment do not submit compensation data for provision of these services. Also, if there are fewer than 4 organizations who submit a role for comparative analysis, market median data is not provided as WTW believes that this would not create a reasonable representation of the market.

UNDERTAKING J16.3

Undertaking

To provide the number of matches within the "General Industry" segment that Aon Hewitt was able to benchmark for OPG.

Response

The 7% of benchmark matches for the General Industry segment referred to at Tr. Vol. 16, p. 66, line 10 in respect of the Aon Hewitt report at EB-2013-0321, Ex. F5-4-1 represents the percentage that these matches were of the total OPG population.

A better comparison between the Aon Hewitt study (EB-2013-0321, Ex. F5-4-1) and the Willis Towers Watson study (Ex. F4-3-1, Attachment 2), would be to look at the matches relative to the General Industry population. Aon Hewitt was able to match 26% (837) incumbents in the General Industry segment. Willis Towers Watson was able to match 66% (1703) incumbents in the General Industry segment, substantially more than Aon Hewitt.

UNDERTAKING J16.4

Undertaking

To advise which, if any, of the comparators in the Towers study were unionized work environments.

Response

Attachment 1 to this response indicates (with an asterisk) the peer companies for which unionized data was available to Willis Towers Watson in both the Total Direct Compensation (TDC) and Pension & Benefits benchmarking study at Ex. F4-3-1, Attachment 2.

The benchmark peer companies voluntarily participate in the surveys and choose which jobs to submit data for based on their business needs and interests. For example, Hydro One has unionized positions, but did not submit compensation data for those unionized positions to Willis Towers Watson in the surveys underlying the TDC benchmark.

For purposes of the TDC and Pension and Benefits benchmarking, OPG's positions were matched against comparable jobs in the peer companies without regard to union status.

Compensation Comparator Organizations

Utility Segment

#	Company (n = 29)	#	Company (n = 29)
1	Alberta Electric System Operator	16	**FortisAlberta Inc.***
2	Alcoa Canada	17	GE Energy
3	Algonquin Power and Utilities Corp.	18	Hydro One Inc.
4	**Altalink***	19	**Hydro Quebec***
5	ArcelorMittal Montreal Inc.	20	Kinross Gold Corporation
6	**ATCO Group***	21	**Newfoundland and Labrador Hydro Electric Corporation***
7	Barrick Gold Corporation	22	Rio Tinto Alcan Canada
8	**BC Hydro Power & Authority***	23	Samuel, Son & Co., Ltd.
9	**Bruce Power LP***	24	**SaskPower***
10	**Capital Power Corporation***	25	**Spectra Energy Transmission*[1]**
11	Chevron Canada Limited	26	**Toronto Hydro Electric***
12	**Enbridge Inc.*[1]**	27	**TransAlta Corporation***
13	**ENMAX Corporation***	28	TransCanada Corp.
14	**EPCOR Utilities Inc.***	29	United States Steel Canada
15	ExxonMobil Canada		

*Companies reporting unionized incumbent data are noted in **purple** and with an asterisk*

1 Data excludes Alberta incumbents

Compensation Comparator Organizations
Nuclear Authorized Segment

#	Company (n = 10)
1	**Bruce Power***
2	Dominion Resources
3	Duke Energy
4	**Entergy***
5	**Exelon***
6	FirstEnergy
7	**NextEra Energy***
8	Public Service Enterprise Group
9	Southern Company Services
10	Tennessee Valley Authority

*Companies reporting unionized incumbent data (for nuclear authorized roles) are noted in **purple** and with an asterisk*

Compensation Comparator Organizations
General Industry Segment – Public Sector

#	Company (n = 23)
Public Sector - weighted 50% for benchmarking purposes	
1	Alberta Electric System Operator
2	Alberta Energy Regulator (previously Energy Resources Conservation Board)
3	Bank of Canada
4	**BC Hydro Power & Authority***
5	British Columbia Lottery Corporation
6	**Canada Post***
7	**Canadian Broadcasting Corporation/Radio Canada***
8	CPP Investment Board
9	**ENMAX Corporation***
10	**EPCOR Utilities Inc.***
11	**Healthcare of Ontario Pension Plan***
12	**Hydro-Québec***
13	**Insurance Corporation of British Columbia (ICBC)***
14	**Loto-Québec***
15	**Newfoundland and Labrador Hydro Electric Corporation***
16	**SaskPower***
17	**SGI Canada***
18	**Toronto Hydro Electric***
19	**Treasury Board of Canada Secretariat***
20	University Health Network
21	VIA Rail Canada Inc.
22	**Workplace Safety & Insurance Board – Ontario***
23	**York University***

*Companies reporting unionized incumbent data are noted in **purple** and with an asterisk*

Compensation Comparator Organizations

General Industry Segment – Private Sector

#	Company (n = 58)	#	Company (n = 58)
	Private Sector - weighted 50% for benchmarking purposes		
1	The Coca-Cola Company-Canada	30	Kinross Gold Corporation
2	Air Canada	31	Kruger Inc.
3	Alcoa Canada	32	**Loblaw Companies Limited***
4	Algonquin Power and Utilities Corp.	33	**Magna International Inc.***
5	AMEC Americas Limited	34	Manulife Financial Corporation
6	**ATCO Group***	35	Maple Leaf Foods Inc.
7	ATS Automation Tooling Systems Inc	36	McCain Foods Limited
8	Bank of Montreal	37	Molson Coors Canada
9	**BCE Inc.***	38	**Nexen Energy ULC***
10	**Bruce Power LP***	39	Nissan Canada, Inc.
11	Canada Colors and Chemicals Limited	40	Parmalat Canada
12	Canadian Imperial Bank of Commerce	41	Procter & Gamble Inc.
13	Canadian National Railway	42	Purolator Inc.
14	Canadian Pacific Railway Ltd.	43	RBC Financial
15	Canadian Tire Corporation	44	Rio Tinto Alcan Canada
16	**Capital Power Corporation***	45	**RioCan Real Estate Investment Trust***
17	Cargill Limited	46	**Rogers Communications Inc.***
18	Celestica Inc.	47	Rothmans Bensons & Hedges
19	Chevron Canada Limited	48	Samuel, Son & Co., Ltd
20	**Enbridge Inc. *[1]**	49	Scotiabank
21	Encana Corporation	50	Spectra Energy [1]
22	Ernst & Young Canada	51	Sun Life Financial
23	FCA Canada Inc. (Formerly Chrysler Canada Inc.)	52	Talisman Energy Inc.
24	Federal Express Canada Ltd.	53	TD Bank Financial Group
25	Ford Motor Company of Canada, Limited	54	Toyota Motor Manufacturing Canada
26	General Electric Canada	55	**TransAlta Corporation***
27	Gerdau Long Steel North America	56	TransCanada Corp.
28	Hydro One Inc.	57	**Unilever Canada***
29	Johnson and Johnson Canada	58	**Viterra Inc***

*Companies reporting unionized incumbent data are noted in **purple** and with an asterisk*

1 Data will exclude Alberta incumbents

Compensation Comparator Organizations
Pension & Benefits Analysis

#	Public Sector (n=12)	#	Private Sector (n=12)
1	**British Columbia Hydro and Power Authority*[1]**	13	**Bruce Power***
2	**Canada Post Corporation***	14	**Canadian Imperial Bank of Commerce***
3	**Canadian Blood Services***	15	Canadian Tire Corporation
4	**ENMAX Corporation***	16	**Enbridge Gas Distribution***
5	**EPCOR Utilities***	17	Honda Canada[†]
6	**Hospital for Sick Children, The*[1]**	18	Kinross Gold Corporation
7	**Hydro One*[1]**	19	**Maple Leaf Foods*[1]**
8	**Hydro-Québec***	20	**Rogers Communications***
9	**Ontario Public Service***	21	**Samuel, Son & Co*[†1]**
10	**SaskPower***	22	Sun Life Financial
11	**Toronto Hydro-Electric System Limited***	23	**TransAlta Corporation***
12	**Workplace Safety & Insurance Board***	24	TransCanada Corp.

Companies with unionized employees, who have identical or similar benefits provided to their salaried non-union employees *are noted in **purple** and with an asterisk*

1 Excluded from Society/PWU positioning.
[†] Excluded from Senior Executives positioning.

UNDERTAKING J16.5

Undertaking

To provide an explanation for how Willis Towers Watson arrives at 30% for the 2015 pension and benefits (excluding statutory benefits) benchmarking results.

Response

The following response was prepared in consultation with Willis Towers Watson (WTW):

Similar to the methodologies of other providers of benefits and human capital services, the WTW methodology helps organizations estimate the employer-provided value of a pension and benefits program for their most prevalent employee demographics. Based on a set of actuarial assumptions, the estimated employer-provided value of a program depends on many factors, including the design of the plan, employee age, service, pay and choices that employees make. This helps companies make decisions about the elements of the programs that provide value to their employees.

The purpose of benchmarking the value of programs is to present an apples-to-apples benchmark comparison of programs.

To achieve an apples-to-apples comparison, WTW uses a standard, common set of actuarial assumptions to determine the average value of each program for a given population or employee profile, and expresses the result as a single percentage of pay. In order to estimate this value for OPG, WTW used these assumptions and applied the most prevalent OPG demographic profiles (age, years of service, pay) within each group (PWU, Society, and Management) to derive the value of the plan provisions applicable to those groups. The resulting values were then expressed as a percentage of OPG salaries on an incumbent weighted basis within each group. The aggregate average value of OPG's pension and benefits expressed as a percentage of base salary at OPG is approximately 30%. WTW then used the same standard assumptions and OPG demographic profiles to examine and value the pension and benefits plan design of comparator organizations. WTW then derived a market median for these organizations. The estimated value of the median market plan value was expressed as a percentage of base salary at OPG. The median value ranges between 20% and 23% of base salary.

The common set of actuarial assumptions applied in determining the employer-provided value of both OPG and comparator organizations' plan provisions were not specific to OPG or any other organization.

It is important to note that the value of an employer-provided benefit to an employee is different than its cost. Program costs are based not only on program design but also vendor costs, utilization factors and other actuarial assumptions, funding policies and other aspects that vary from one company to another.

Here are some specific examples to illustrate the difference between value and cost:

- The benchmark value of a pension plan is determined assuming each company has the same return on the assets in their pension fund. The cost of the same pension plan will be higher for a company whose pension investments are expected to earn 5% annually than one whose pension investments are expected to earn 7%. Differences in actual investment earnings on pension investments also would impact cost. Differences in investment returns may be a function of differences in the cash flow profile of the liability, strategic asset allocation, or risk management approaches, for example.

- The benchmark value of a pension plan is determined assuming employees' future salaries increase by the same percentage at all organizations, while the benchmark value of all post-retirement benefits is determined using a common mortality table. In practice, different organizations will have different assumptions regarding future salary increases and may apply different mortality assumptions, depending on their particular circumstances including characteristics of employee (and retiree) populations, labour market and compensation expectations, and actuaries' judgement. These and other differences in key actuarial assumptions can lead to significant variability in cost levels.

- The benchmark value of a benefit plan is determined using average medical, dental and disability claims. The cost of a benefit plan will be higher for a company whose employees require relatively more expensive drug therapies or have generally higher utilization rates, have more dependent children (e.g., requiring orthodontics), or experience higher rates of disability.

- The benchmark value of a flexible benefit plan is determined assuming employees elect the most common benefit option. The cost of a benefit plan is based on actual employee elections, recognizing that some options are more expensive to the company than others.

Companies like WTW benchmark "value" as opposed to "cost" as it enables an apples-to-apples comparison of the plan provisions, keeping all other variables constant. Costs reflect plan provisions and many other plan-specific variables such as pension fund

returns, population age, population health and employee elections, and actuaries' judgement regarding assumptions of future events. In addition, underlying assumptions used for benchmarking or costing purposes will differ from actual experience. Experience gains or losses are reflected as part of costs in subsequent periods.

Therefore, actual cost for OPG in a given period can be higher or lower than the 30% of base salary benchmark value and the actual cost for comparator organizations can be higher or lower than the 20-23% of base salary median value. As such, pension and benefits benchmarking provides a reasonable basis for comparing the relative percentage-of-pay value for a company's pension and benefits program, but not its accounting or funding cost. For the reasons outlined above, there is no industry standard basis for carrying out "cost" benchmarking. In WTW's judgement, it would not be practical to attempt "cost" benchmarking and we do not expect that such an exercise would yield meaningful results.

OPG consulted with Aon Hewitt, its independent actuary, who shared the view that cost benchmarking of pension and benefits plans would not achieve meaningful results.

UNDERTAKING J16.6

Undertaking

Ref: K16.2, pp. 50-51

To provide OPG's forecasted 2019-2021 contribution ratios and total employer contributions on a confidential basis.

Response

Consistent with the projected results of the January 1, 2019 funding valuation assumed in OPG's 2017-2019 Business Plan, as described in Ex. N1-1-1, p. 7, line 8 to p. 8, line 3 to p.8, forecast contribution amounts to the RPP are as follows (on a total OPG basis):

($M)	**2019**	**2020**	**2021**
Current Service (Employer)	198	204	210
Special Payments	101	101	98
Employee Contributions	[redacted]		
Employer/Employee Contribution Ratio (%)	[redacted]		

UNDERTAKING J16.7

Undertaking

For all of the costs identified in part c of L-6.6-19 SEP-015, identify which, if any, can be attributed to FTEs.

Response

The response in L-6.6-19 SEP-015 included non-regular labour costs in addition to contractor costs. A corrected response is provided below which only addresses contractors as requested in the interrogatory:

> "Base OM&A ~~includes contractor costs~~ for 2015 includes ~~of $30.2M for non-regular labour,~~ $4.4M for augmented staff and $108.4M for other purchased services (see Ex. F2-2-1 Table 2). Outage OM&A ~~includes contractor costs~~ for 2015 ~~of $19.9M for non-regular labour,~~ includes $25.8M for augmented staff and $123.3M for other purchased services (see Ex. F2-4-1 5 Table 3)."

As mentioned at Tr. Vol. 16, p. 136, lines 22-28 and p. 137, lines 1-7, non-regular labour is attributed to FTEs in Ex. F4-3-1, Attachment 1, whereas contractor costs (e.g. augmented staff and other purchased services), are not attributed to FTEs (see Tr. Vol. 16. p. 138, lines 17-20).

UNDERTAKING J16.8

Undertaking

To provide a breakdown of what the major components of the forecast "other purchased services" cost are.

Response

Figure 1 below lists the services provided by the top seven vendors (by dollar amount) for the Nuclear Base OM&A Other Purchased Services. Together these vendors comprise over 60% of Nuclear Base OM&A Other Purchased Services in 2015.

Figure 1

Vendor	Description of Base OM&A Services
CANDU Owners Group	Provider of programs for the support, development, operation and maintenance of CANDU reactor technology [1]
Unitech Services Group	Provider of off-site laundry services
Kinectrics	Provider of various engineering services such as environmental compliance sample analysis services
Tetra Tech Wei Inc	Provider of engineering services designed to reduce engineering holds so that execution of work plans can proceed on a timely basis [2]
AMEC NSS Limited	Provider of various engineering services such as safety analysis services; seismic testing, and criticality coding assessments [3]
Black and MacDonald Ltd	Provider of steady state maintenance services e.g. maintenance on standby generator, removal of asbestos, work activities associated with forced outage
E S Fox Ltd	Provider of steady state maintenance services e.g. maintenance on vault vapour recovery driers, work activities associated with forced outage

[1] The objective of the OPG's nuclear R&D program is to develop knowledge, tools and methods to address various technical, design basis, and operational issues in its fleet of CANDU reactors. Experience has shown that R&D in support of OPG's nuclear plants is most cost-effectively handled on a shared-basis with other CANDU owners. OPG contracts with the CANDU Owners Group, a not-for-profit organization, to provide such services as developing, validating, and qualifying industry standard computer codes used in nuclear safety analysis in support of reactor design and licensing base as well as investigating materials and system degradation issues that impact the safety and reliability of the plants (e.g. fuel channels, feeders, and steam generators). This work can include developing mitigation strategies, non destructive examination methods and tools, fitness-for-service guidelines, and assessment techniques

[2] As part of the work control process that ensures a task is correctly planned, planners may seek information from a support organization such as Engineering. A hold is a request for work to be performed in support of work being planned through the work control process. This planning of work is sometimes termed as "getting work ready" for execution of the daily plan, which requires resolution of the hold.

[3] Pickering and Darlington are large and complex plants with many thousands of components. Some components are more important than others in terms of nuclear safety and production. For this reason, OPG categorizes plant components into four different groups, from CC1, which are our most important (highly critical), to CC4, which are run to maintenance components. All other components are coded Not Applicable (NA) because they have no impact on nuclear safety or production. It's extremely important and prudent to correctly categorize components so maintenance activities have the right priority, and our most important equipment is repaired first.

UNDERTAKING J17.1

Undertaking

Provide the most current integrated vendor performance scorecard for each of the ESMSA vendors on a confidential basis.

Response

OPG has three ESMSA contractors: (1) ES Fox, (2) Black & McDonald, and (3) the SNC/Aecon Joint Venture.

There is currently no scorecard available for the SNC/Aecon Joint Venture. The SNC/Aecon Joint Venture was engaged as an ESMSA contractor on December 19, 2014 and did not complete a significant amount of work in 2015. The scorecard for its 2016 performance is still being prepared as OPG is currently reviewing the Heavy Water Storage Facility project (see Ex. N2-1-1), which will inform the preparation of the 2016 ESMSA performance scorecard for the SNC/Aecon Joint Venture.

The most current operational performance scorecards for ES Fox and Black & McDonald are provided entirely in confidence as Attachment 1 and Attachment 2, respectively. In addition to capital project work, these scorecards encompass work the ESMSA contractors undertake for outages, minor modifications and minor projects. As discussed in Ex. D2-2-3, p. 20, under the ESMSAs, a percentage of each contractor's invoice (inclusive of costs, profits and overheads), is withheld by OPG and contributed to a performance fee pool. The scorecard then informs what percentage of the fees held at risk by OPG are returned to each contractor. As a result, a score of less than 100% means that OPG retains some of the fees that were due to the contractor. Such retained fees are then allocated on a *pro rata* basis back to project costs.

These scorecards do not capture all projects completed by each contractor as larger, more complex projects subject to a performance fee may have their own tailored performance scorecard.

ATTACHMENT 1

FILED CONFIDENTIAL IN ITS ENTIRETY

ATTACHMENT 2

FILED CONFIDENTIAL IN ITS ENTIRETY

UNDERTAKING J17.2

Undertaking

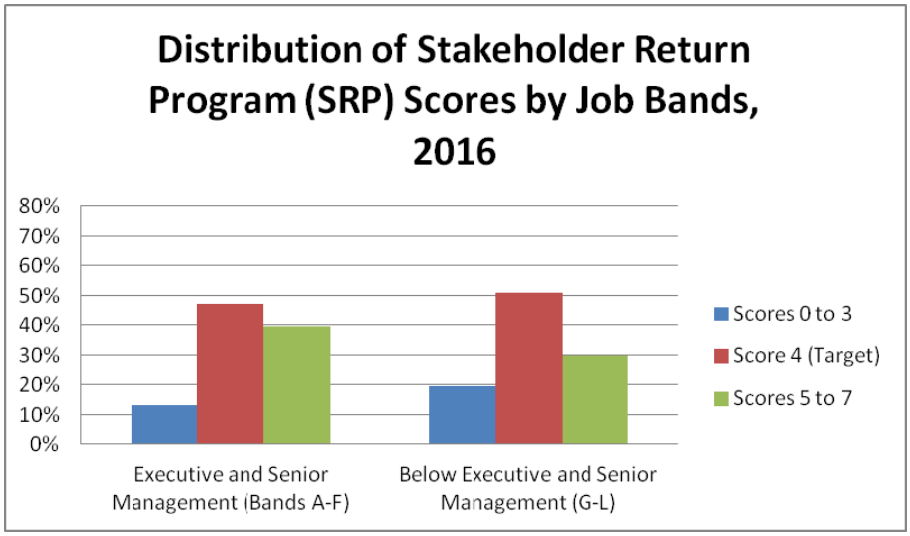
Reference: L-6.6-15 SEC-076, Attachment 2

To recreate with the 2016 actuals, the Stakeholder Return Program distributions.

Response

Graph 1 below shows the distribution of 2016 actual SRP scores on the same basis as L-6.6-15-SEC-076, Attachment 2 and is consistent with Figure 10 on p.168 of the 2013 Annual Report of the Office of the Auditor General Ontario.

Graph 1



UNDERTAKING J17.3

Undertaking

To provide the total cost OPG is paying to augmented staff and the associated FTEs.

Response

In determining the most cost effective approach to completing planned work programs, OPG considers available resource options, including augmented staff to supplement its workforce and manage peak demands. Augmented staff are also utilized to help address labour declines experienced as a result of greater than anticipated attrition and subsequent hiring lags, such as in 2016. (see also J14.3 and J15.12).

In 2016, OPG incurred approximately $83M in costs for external vendors for augmented staff to complete Nuclear OM&A, capital and nuclear liabilities funded work programs. This total amount comprises approximately $44M for Nuclear Operations, including outage related inspection and maintenance testing, approximately $32M for the Darlington Refurbishment Program (DRP), and an additional $7M in allocated corporate support costs for Nuclear Operations.

OPG does not track FTE associated with augmented staff. Based on month end headcount information, for the purpose of this response, OPG has estimated that there were on average 416 FTE directly supporting the Nuclear business in 2016, of which 180 FTE was for DRP. Using the ratio of direct costs per FTE based on the above total costs for the Nuclear business, OPG estimates that there were 39 FTE allocated to Nuclear Operations from corporate support, for a total of 455 FTE including DRP.

Augmented staff supporting steady state operations were considered in the Goodnight benchmarking study at Ex. F3-1-1, Attachment 1 (see L-6.2-1 Staff 109, and EB-2013-0321, Ex. F5-1-1, Part A, p. 17).

UNDERTAKING J17.4

Undertaking

To confirm whether the Auditor General is aware of OPG's revised 2016 rehire policy.

Response

OPG has not discussed with the Auditor General the refinements made to the rehire procedure.

These refinements were made to enable the business to meet its work program needs in a cost-effective manner and recognize that former OPG employees represent an experienced talent pool that can be drawn upon for their unique skills and experience. This is particularly true for individuals who have been licensed by the Canadian Nuclear Safety Commission as there is not a ready supply of talent available in Canada.

These refinements have not removed the underlying controls associated with the Auditor General's recommendations. The primary control feature of the rehire procedure that relates to the Auditor General's recommendations to improve succession planning and knowledge retention / transfer and thereby minimize the use of rehires, is the use of a waiting and working period. Waiting and working periods continue to be utilized in the revised procedure.

Additional controls to ensure optimal utilization of staff resources and a healthy succession pipeline for talent have also been put in place through the Resource Planning & Control Team (RPCT) as described in L-1.2-2-AMPCO-005.

UNDERTAKING J17.5

Undertaking

Ref: K17.1, page 43 (Public Sector Salary Disclosure)

For salaries $200k or greater, provide the breakdown of unionized staff versus management.

Response

The table below provides the number and percentage of employees who were paid $200K or more by year and union status, as shown on the Public Sector Salary Disclosure Act (PSSDA) list. The definition of salary used under the PSSDA includes all amounts reported as employment income on the Canada Revenue Agency T4 slips. This includes base salaries, incentives, shift premiums, other allowances, and overtime paid to employees. All amounts are reported in the year they are paid, which may vary from the year they are earned and recognized in OPG's costs.

Employees with PSSDA Salaries > $200K	2013		2014		2015		2016	
	#	% of T4's (total)	#	% of T4's (total)	#	% of T4's (total)	#	% of T4's (total)
Management	175	1.3%	141	1.1%	174	1.4%	168	1.3%
Union	351	2.6%	228	1.8%	254	2.0%	337	2.6%
Total Employees > $200K	526	3.9%	369	2.9%	428	3.4%	505	4.0%
Total Number of T4s Issued	13504		12815		12558		12771	

The number of management paid over $200K in any given year is influenced by corporate performance as reflected in OPG's Corporate Balanced Scorecard. Please refer to JT3.1 for a copy of OPG's scorecard results for 2013 through 2015.

- Below plan performance in 2013 resulted in lower pay at risk incentives being paid in 2014 and a reduction in the number of management paid over $200K in 2014.

- Strong corporate performance in 2014 resulted in higher pay at risk incentives being paid in 2015, increasing the number of management paid over $200K in 2015.

- Corporate performance in 2015 was slightly above plan, resulting in lower pay at risk incentives being paid in 2016 as compared to 2015, and a reduction in the number of management paid over $200K in 2016.

For union positions, the combined effect of base salaries, overtime, shift premiums, and other allowances will affect the numbers on the list in any year.

Year over year changes in the number of union represented employees who were paid over $200K in any year is influenced by work program demands and the associated overtime that is worked to return units to service during an outage and complete priority work when staffing levels are below plan. In years where more overtime is utilized, the number of union represented employees paid over $200K has increased, and conversely, when less overtime was utilized the number has decreased.

In addition to overtime, another factor contributing to the overall number of union represented employees being paid over $200K includes the allowances paid to nuclear authorized staff in recognition of obtaining and recertifying their licenses with the Canadian Nuclear Safety Commission. Approximately 4% of OPG's union represented employee populations are in Nuclear Authorized positions which have licensing requirements. The amount of allowance paid varies by role and how long an individual has been licensed for, and serves as a mechanism to retain these individuals who are critical to OPG's safe and reliable operations.

UNDERTAKING J17.6

Undertaking

Ref: K17.1, page 43 (Public Sector Salary Disclosure)

For salaries $200k or greater, to provide the number of earners/total people included in the public sector salary disclosure for 2014 to 2016.

Response

Please refer to Undertaking J17.5.

UNDERTAKING J17.7

Undertaking

Ref: K17.1, page 43 (Public Sector Salary Disclosure)

For salaries over $300k, to provide what types of positions are captured.

Response

The table below provides the number and percentage of employees who were paid $300K or more by year and position type, as shown on the Public Sector Salary Disclosure Act (PSSDA) list. The definition of salary used under the PSSDA includes all amounts reported as employment income on the Canada Revenue Agency T4 slips. This includes base salaries, incentives, shift premiums, other allowances, and overtime paid to employees. All amounts are reported in the year they are paid, which may vary from the year they are earned and recognized in OPG's costs.

Employees with PSSDA Salaries > $300K	2013		2014		2015		2016	
	#	% of T4's (total)	#	% of T4's (total)	#	% of T4's (total)	#	% of T4's (total)
Executive (Bands A to E)	36	0.3%	28	0.2%	32	0.3%	28	0.2%
Nuclear Authorized Management (Bands F to G)	0	0.0%	1	0.0%	12	0.1%	23	0.2%
Management	36	0.3%	29	0.2%	44	0.4%	51	0.4%
Nuclear Authorized Union (Society & PWU)	10	0.1%	2	0.0%	2	0.0%	7	0.1%
Other Union (Society & PWU)	2	0.0%	0	0.0%	2	0.0%	1	0.0%
Union	12	0.1%	2	0.0%	4	0.0%	8	0.1%
Total Employees > $300K	48	0.4%	31	0.2%	48	0.4%	59	0.5%
Total Number of T4s Issued	13504		12815		12558		12771	

Less than 0.5% of OPG's employees have been paid over $300K, and is primarily comprised of individuals in Executive positions (Bands A to E) or jobs that require

individuals to be or to have been licensed by the Canadian Nuclear Safety Commission (Nuclear Authorized).

The number of executives and nuclear authorized management paid over $300K in any given year is directly influenced by corporate performance as reflected in OPG's Corporate Balanced Scorecard, as described in J17.5.

UNDERTAKING J17.8

Undertaking

Ref: SMART Objectives Audit JT3.4, Attachment 9

To provide any target set and/or expected to be met in 2017 with respect to SMART Objectives.

Response

For 2017, OPG is targeting to have greater than 70% of performance plans include at least three high quality objectives that incorporate the underlying SMART principles. This target represents an improvement over previous audit results and recognizes that the development of skills in writing objectives will be realized over time through practice and training.

UNDERTAKING JX17.9

Undertaking

To provide the source document that restricts that restricts OPG from providing information regarding Nuclear Security Guards.

Response

OPG is not permitted to release security protected prescribed information pursuant to Sections 21 (1) (c) and 23 (1) of the General Nuclear Safety and Control Regulations ("Regulation") under the *Nuclear Safety and Control Act*.

The Regulation prohibits the release of information relating to nuclear security arrangements, since the release of this information could jeopardize the protection of OPG critical infrastructure, assets, facilities, and systems; or endanger the security of a building. Information relating to security arrangements includes the number of security staff at its nuclear facilities. To OPG's knowledge, this interpretation is shared by other nuclear operators, such as Bruce Power. OPG believes that security arrangements exclude individual compensation.

Both number of staff and compensation information is required for purposes of benchmarking. As such, OPG was not able to include its nuclear security guard job category as part of the Willis Towers Watson benchmarking study.

UNDERTAKING JX17.10

Undertaking

To provide calculations and assumptions provided to government for purposes of meeting Net Zero.

Response

Labour Relations Confidential

Provided below are the figures provided to the Government for the purposes of demonstrating that the results of OPG's collective bargaining with the PWU and the Society met the mandate of achieving a net neutral cost to electricity ratepayers. The figures are presented on the basis of contract years, consistent with how information was provided to the Government. As noted in Ex. L-6.6-15 SEC-072, the Government assessed these results on a total OPG basis. The results were determined based on information available at the time of bargaining, generally using conservative assumptions (see Tr. Vol. 17, p. 87, line 21 to p. 88, line 11 and Tr. Vol. 17, p. 91, line 13 to p. 94, line 8).

As noted at Ex. F4-3-1, p. 15, lines 16-23, Ex. L-6.6-1 Staff 147, Attachment 1, and as explained at Tr. Vol. 17, p. 84, line 27 to p. 85, line 21, the costs/savings related to pension reform were not considered as part of achieving the "net neutral" mandate. As noted at Ex. F4-3-1, p. 15, line 23, Ex. L-6.6-1 Staff-147(c), and Tr. Vol. 17, p. 80, line 19 to p. 81, line 3, the Government was satisfied that OPG had met the "net neutral" mandate.

The estimated overall net savings over the term of each of the collective agreements identified below are as provided in Ex. L-6.6-1 Staff-147(c).

Chart 1
PWU Collective Agreement Impacts (Total OPG)

Item	Costs / (Savings) $M			
Numbers may not add due to rounding	**Apr 1, 2015 to Mar 31, 2016** (a)	**Apr 1, 2016 to Mar 31, 2017** (b)	**Apr 1, 2017 to Mar 31, 2018** (c)	**Apr 1, 2015 to Mar 31, 2018** (a)+(b)+(c)
3-Year Wage Increases at 1%/year (excl. impact on pension contributions)[1]				
Higher OPG Pension Contributions Due to 1%/year Wage Increases[1]				
250-Hour Purchased Services Threshold[2]				
Nuclear Outage Purchased Services Agreement[2]				
Radiation Protection Technician (RPT) Appendix A Midterm[2]				
Project Technician Purchased Services Agreement[2]				
Targeted Severance Provision[3]				
Term Employees (re: Pickering Closure)[4]				
Temporary Work Headquarters Travel Time Provisions[2]				
Out-of-Country Medical Coverage Improvement[5]				
Paramedical Benefit Improvements[5]				
Net Savings				

Numbers may not add due to rounding

Notes:

1. The equivalent items were combined into a single line "3-Year Wage Increases at 1%/year" in Ex. L-6.6-15 SEC-072 Chart 1. In addition to being Total OPG amounts, these amounts differ from Ex. L-6.6-15 SEC-072 in that they are based on regular labour cost information used at the time of bargaining, whereas Ex. L-6.6-15 SEC-072 provided estimated impacts consistent with the planned regular labour costs and pension forecasts underpinning this Application.

2. Amounts in Ex. L-6.6-15 SEC-072 Chart 1 for these items represent the nuclear business' portion of the above Total OPG amounts.

3. Excluded from Ex. L-6.6-15 SEC-072 as explained at Tr. Vol. 17, p. 81, lines 4-20 and p. 83, line 13 to p. 84, line 8.

4. Excluded from Ex. L-6.6-15 SEC-072 as no Term Employees were assumed in OPG's 2016-2018 Business Plan underpinning this Application, due to uncertainties related to the extent of their future utilization, partly in light of the decision to pursue the extension of Pickering commercial operations beyond 2020, as reflected in that plan. The primary savings during the IR Term from the potential use of Term Employees, compared to regular employees, would relate to the Term Employees not being entitled to pension or benefits. Any such savings realized for pension or other post employment benefits during the IR Term would be captured in the Pension & OPEB Cash to Accrual Differential Deferral Account, Pension & OPEB Cash Payment Variance Account and/or Pension and OPEB Cost Variance Account, as applicable. See Ex. L-6.6-2 AMPCO-132 for further information on Term Employees.

5. Due to their relatively small value, these items were combined into a single line "Minor Benefit Improvements" in Ex. L-6.6-15 SEC-072 Chart 1. Amount in Ex. L-6.6-15 SEC-072 represents the nuclear business' portion of the above Total OPG amounts.

Chart 2
Society Collective Agreement Impacts (Total OPG)

Item	Costs / (Savings) $M			
	Jan 1 to Dec 31, 2016 (a)	**Jan 1 to Dec 31, 2017** (b)	**Jan 1 to Dec 31, 2018** (c)	**Jan 1, 2016 to Dec 31, 2018** (a)+(b)+(c)
3-Year Wage Increases at 1%/year (excl. impact on pension contributions)[1]				
Higher OPG Pension Contributions Due to 1%/year Wage Increases[1]				
Purchased Services Agreement LOU #193[2]				
Overtime PWU Rate Equivalency[2]				
Hours of Work Averaging Permit[2]				
Time-Limited Out-of-Country Medical Coverage Improvement[3]				
Time-Limited Prescription Dispensing Fee Coverage Improvement[3]				
Temporary Work Headquarters Meal Allowance Provisions[4]				
Shift Differential Increase[4]				
Elimination of Band N Goal Sharing Equivalent Payment[2]				
Medical Absent Report Fee Coverage Improvement[4]				
Net Savings				

Numbers may not add due to rounding

Notes:

1. The equivalent items were combined into a single line "3-Year Wage Increases at 1%/year" in Ex. L-6.6-15 SEC-072 Chart 2. In addition to being Total OPG amounts, these amounts differ from Ex. L-6.6-15 SEC-072 in that they are based on regular labour cost information used at the time of bargaining, whereas Ex. L-6.6-15 SEC-072 provided estimated impacts consistent with the planned regular labour costs and pension forecasts underpinning this Application.

2. Amounts in Ex. L-6.6-15 SEC-072 Chart 2 for these items represent the nuclear business' portion of the above Total OPG amounts.

3. Due to their relatively small value, these items were combined into a single line “Minor Benefit Improvements” in Ex. L-6.6-15 SEC-072 Chart 2. Amount in Ex. L-6.6-15 SEC-072 represents the nuclear business’ portion of the above Total OPG amounts.

4. Due to their relatively small value, these items were combined into a single line “Other Miscellaneous Items” in Ex. L-6.6-15 SEC-072 Chart 2. Amount in Ex. L-6.6-15 SEC-072 represents the nuclear business’ portion of the above Total OPG amounts.

UNDERTAKING JX17.11

Undertaking

To provide pension contributions, lump sum payments, and share grant calculations beyond IR period, including assumptions, for both PWU and Society.

Response

Chart 1 below summarizes the total projected savings associated with increased employee contributions for PWU and Society represented employees and the total projected costs associated with the lump sum payments and the Share Performance Plan payments, as attributed to the nuclear facilities, for the 2017-2032 period. These payments apply to eligible employees contributing to the pension plan as of April 1, 2015 (PWU) and January 1, 2016 (Society). The last payment under the plan will be made at the beginning of 2032.

Chart 1
Pension Contribution Savings and Share Performance Plan Impacts
(Attributed to Nuclear)

$M	**IR Term 2017-2021**[1]	**2022-2032**	**Total 2017-2032**
Increased Employee Pension Contributions Savings	88	[redacted]	
Lump Sum Payments and Hydro One Share Performance Plan Costs	(92)		
Net (Cost) Savings	(4)		

This analysis demonstrates that the savings from higher employee contributions will significantly exceed the costs associated with the Share Performance Plan and lump sum payments over the 2017-2032 period, by approximately [redacted]. The benefits of higher employee contributions will further continue for the life of the pension plan, as the increased employee contributions do not have a specified end date and will apply to all existing and future employees. Also of note is that the cumulative savings from higher

[1] As per Ex. L-6.6-1 Staff-147 (d) and (g).

employee pension contributions are anticipated to exceed the cumulative costs of the payments to employees by 2022.

The pension contribution savings figures attributed to the nuclear facilities post 2021 were based on total OPG values calculated by Aon Hewitt, OPG's actuary, using an indicative longer-term headcount profile supplied by OPG and associated projected payroll, assuming wage growth consistent with actuarial assumptions set out in Ex. F4-3-2, Chart 5. The nuclear allocation for the period prior to the shutdown of the Pickering station was based on the 2021 nuclear allocation factor for pension and OPEB amounts reflected the pre-filed evidence. The allocation was directionally reduced to account for the shutdown of the Pickering station in subsequent years.

The post 2021 Share Performance Plan cost figures were calculated in the same manner as those shown in Ex. L-6.6-15 SEC-078, based on an estimated number of eligible employees (continuing the declining trend shown in Ex L-6.6-15 SEC-078 (a)). The number of eligible employees was estimated taking into account forecast attrition, based on the number of staff eligible to retire in a given year and considering both past experience and future expectations regarding how long employees continue working after becoming eligible to retire, on average.

UNDERTAKING J17.12

Undertaking

TO DESCRIBE HOW THE REMOVAL OF D2O PROJECT FROM THE APPLICATION AND THE CIRCUMSTANCES SURROUNDING THAT HAS BEEN HANDLED ON A CORPORATE SCORECARD BASIS FOR THE YEARS IN WHICH THEY WOULD HAVE IMPACTED THE SCORECARD.

Response

In 2016, a score of 0 was assigned to the Campus Plan Metric. This metric consists of milestones for 3 discrete Campus Plan projects: an interim milestone related to the Heavy Water project (D2O) which was achieved, and milestones for installation of the Third Emergency Power Generator and Containment Filtered Venting System which were not achieved. The integrated score for the 3 projects was adjusted to 0, and had a weighting of 10% on the 2016 scorecard.

In 2017, the Refurbishment Project Cost measure may be impacted if the cost of the D2O project exceeds the overall project budget, including contingency, for the planned 2017 work, and other savings to offset costs cannot be found. This work is currently scheduled for completion in 2017. The Refurbishment Project Cost has a 10% weighting on the 2017 Corporate Balanced Scorecard.

UNDERTAKING J17.13

Undertaking

To advise of the proportion of employees that falls within 35, 37.5 and 40 hour working hour weeks.

Response

The proportion of employees in Nuclear Operations whose standard hours of work are 35, 37.5 and 40 hours per week is shown in the Table 1 below.

Table 1

Nuclear Operations[1]				
Standard Weekly Hours	**PWU**	**Society**	**Management**	**Total**
35	4%	66%	96%	32%
37.5	2%			1%
40	94%	34%	4%	67%

Willis Towers Watson (Towers) does not make any adjustment for hours worked per week for purposes of its Total Direct Compensation (TDC) benchmarking at Ex. F4-3-1, Attachment 2. Towers advises that for TDC benchmarking annualized salary is the most comparable element to use because it integrates various company policies such as paid time off, formal vacation and hours of work which different companies will use in different combinations. Making adjustments on one element such as hours of work without considering the other elements undermines the purpose of benchmarking which is to create as standardized a comparison as possible from one company to the next, recognizing that individual policies vary.

Towers' approach to TDC benchmarking is consistent with industry practices where annualized salary is the comparator used for purposes of TDC benchmarking.

[1] This information is based on current employee populations (regular staff only) and does not include corporate allocated support or employees working directly for the Darlington Refurbishment.

UNDERTAKING J17.14

Undertaking

Reference: Tr. Vol. 17, p. 141, lines 4-16

To explain why some security staff earning less than $100k are on the Public Sector Salary Disclosure list; are these employees all working at the top of their range or are they working significant amounts of overtime?

Response

PWU Nuclear Security Officer positions are a protected classification as described in Ex. JX17.9 and were excluded from the Willis Towers Watson Compensation Benchmarking Study at Ex. F4-3-1, Attachment 2, and the Goodnight Staffing Benchmarking Study at Ex. F2-1-1, Attachment 2.

The average base salary for PWU Nuclear Security Officer positions was $84.7K as of December 31, 2016. The 2016 salary range for these positions was $52K to $93.7. In testimony, Ms. Rees, indicated that the top of the 2015 range was $85K, but this figure was incorrect as it did not include all the PWU nuclear security job classifications (Tr. Vol. 17, p.75, lines 14-21).

Under the PWU collective agreement, Security Officer positions are entitled to overtime and allowances, including shift premiums, which can materially increase compensation. Overtime and allowance provisions are common in unionized environments, and are also included for comparable positions in organizations from which OPG would attract and lose talent, such as the Durham Regional Police and Ontario Provincial Police forces.

Since the definition of salary used under the *Public Sector Salary Disclosure Act* includes all amounts reported as employment income on the Canada Revenue Agency T4 slips, with overtime and allowances, some of these Security Officer positions will be captured on the Public Sector Salary Disclosure (PSSD) list.

Beyond the Nuclear Security Officer job classifications, the term “Security” appears in job titles for other positions within OPG in areas such as IT, corporate security, and emergency services. In these areas, there are supervisors, managers, and directors with the word “security” in their titles whose compensation will place them on the PSSD list.

UNDERTAKING J18.1

Undertaking

To provide any communications from OPG to the government made in the process of seeking approval of Pickering Extended Operations, in particular regarding the risk posed by the aging of the reactor

Response

OPG's 2016-2018 Business Plan (Ex. A2-2-1 Attachment 1) outlined key risks to the Business Plan, including the adverse impact of life management and equipment aging issues on nuclear generation, as follows (p. 8):

> As Pickering station operations are extended further to 2024 and the Darlington station prepares for an additional 30+ years of operating life, management of life limiting and other critical components is essential to ensuring reliability and predictability in generation performance of the stations. Early identification of age-related degradation of station components and discovery of unexpected conditions require a timely risk management and continuing maintenance focus.

The Minister of Energy concurred with OPG's 2016-2018 Business Plan (see JT2.1).

UNDERTAKING J20.1

Undertaking

To provide bill impacts for General service and large volume customers using data from Toronto Hydro, Power Stream and Hydro One.

Response

OPG has been asked to file a bill impact analysis, similar to that prepared for residential customers as part of Ex. I1-1-2 Table 1, but for medium and large volume customers using data from Toronto Hydro, PowerStream, and Hydro One Networks. This analysis is provided in Tables 1, 2, and 3 of Attachment 1 to this response.

There is a difference in presentation between the residential customer bill impacts and those provided for medium and large use customers as part of this response. OPG is able to provide the analysis of the residential bill impact by relying on the OEB's bill impact calculator (provided on the OEB's website[1]). This tool calculates the customer bill for all Ontario electricity distribution companies at an average residential consumption level of 750kWh.

A tool as described above does not exist for medium and large volume customers and OPG, as a wholesale generator, does not have information at a customer class level. To approximate a bill impact, OPG has manually extracted information from the draft rate orders (which provide fuller calculation details not found in the final rate orders) of the identified distribution companies. Each of these utilities has a unique makeup of medium and large use customers and completes bill calculations in a way that is representative of their customer base. The consumption level for the medium and large use customers is different for each of these customer classifications depending on the utility and the calculations are not comparable across the three utilities. OPG is unable to calculate an average bill impact for medium and large volume customers, and must complete the calculation independently for each utility requested.

[1] http://www.ontarioenergyboard.ca/OEB/Consumers/Your+Utility+-+Bill+Calculator

Table 1
Annualized Bill Impact for Typical PowerStream Consumers 2017-2021

Line No.	Description	Note	2017		2018		2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600	82,760	2,896,600
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)**		42,748	1,496,182	42,972	1,504,021	43,306	1,515,713	42,301	1,480,541	41,115	1,439,034
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	14,157	467,845	14,157	467,845	14,157	467,845	14,157	467,845	14,157	467,845
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in Weighted Average Payment Amounts ($/MWh)**	4	1.52	1.52	1.56	1.56	1.60	1.60	1.64	1.64	1.68	1.68
7	**Percentage Increase in Consumer Bills**		0.46%	0.49%	0.47%	0.50%	0.49%	0.52%	0.49%	0.52%	0.49%	0.52%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		65.16	2,280.60	67.14	2,349.87	69.35	2,427.34	69.44	2,430.29	69.18	2,421.21

Notes:

1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Powerstream EB-2015-0003 Draft Rate Order
Medium/Large Business (EB-2015-0003 Draft Rate Order, Schedule B, Page 4): GS > 50 customer, consumption 80,000 kWh, loss factor 3.45%
Large Industrial (EB-2015-0003 Draft Rate Order, Schedule B, Page 5): Large User customer, consumption 2,800,000 kWh, loss factor 3.45%

2 Ex.N3-1-1 Table 1, line 9.

3 Ex. N3-1-1_Table 1, Line 11

4 Ex. N3-1-1_Table 1, Line 8

Table 2
Annualized Bill Impact for Typical Hydro One Networks Consumers 2017-2021

Line No.	Description	Note	2017		2018		2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	37,135	517,000	37,135	517,000	37,135	517,000	37,135	517,000	37,135	517,000
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)** (line 1 x line 3)		19,181.4	267,046.3	19,281.9	268,445.4	19,431.8	270,532.3	18,980.8	264,254.6	18,448.7	256,846.1
5	**Typical Monthly Consumer Bill ($)**	1	6,435	68,653	6,435	68,653	6,435	68,653	6,435	68,653	6,435	68,653
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in Weighted Average Payment Amounts ($/MWh)**	4	1.52	1.52	1.56	1.56	1.60	1.60	1.64	1.64	1.68	1.68
7	**Percentage Increase in Consumer Bills** (line 6 x (line 4/1000) / line 5)		0.45%	0.59%	0.47%	0.61%	0.48%	0.63%	0.48%	0.63%	0.48%	0.63%
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		29.24	407.05	30.13	419.42	31.12	433.24	31.16	433.77	31.04	432.15

Notes:

1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Powerstream EB-2013-0416 Draft Rate Order
Medium/Large Business (EB-2013-0416 Draft Rate Order, Exhibit 7): GSd customer, consumption 35,000 kWh, loss factor 6.1%
Large Industrial (EB-2013-0416 Draft Rate Order, Exhibit 7): ST customer, consumption 500,000 kWh, loss factor 3.4%

2 Ex.N3-1-1 Table 1, line 9.

3 Ex. N3-1-1_Table 1, Line 11

4 Ex. N3-1-1_Table 1, Line 8

Table 3
Annualized Bill Impact for Typical Toronto Hydro Consumers 2017-2021

Line No.	Description	Note	2017		2018		2019		2020		2021	
			Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial	Medium/Large Business	Large Industrial
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Typical Consumer Usage (kWh/Month)**	1	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150	155,640	4,584,150
2	**Total Forecast Production (TWh)**	2	71.1	71.1	71.4	71.4	72.0	72.0	70.3	70.3	68.4	68.4
3	**OPG Portion of Consumer Usage**	3	51.7%	51.7%	51.9%	51.9%	52.3%	52.3%	51.1%	51.1%	49.7%	49.7%
4	**Consumer Usage of OPG Generation (kWh/Month)**		80,392.8	2,367,853.6	80,814.0	2,380,258.7	81,442.3	2,398,763.3	79,552.4	2,343,100.1	77,322.1	2,277,410.5
	(line 1 x line 3)											
5	**Typical Monthly Consumer Bill ($)**	1	27,003	771,057	27,003	771,057	27,003	771,057	27,003	771,057	27,003	771,057
	EB-2013-0321/EB-2014-0370 to EB-2016-0152:											
6	**Increase in Weighted Average Payment Amounts ($/MWh)**	4	1.52	1.52	1.56	1.56	1.60	1.60	1.64	1.64	1.68	1.68
7	**Percentage Increase in Consumer Bills**		0.45%	0.47%	0.47%	0.48%	0.48%	0.50%	0.48%	0.50%	0.48%	0.50%
	(line 6 x (line 4/1000) / line 5)											
8	**Dollar Increase in Consumer Bills ($)** (line 5 x line 7)		122.54	3,609.28	126.26	3,718.89	130.43	3,841.50	130.58	3,846.16	130.10	3,831.79

Notes:

1 Current Approved Rates and Usage (adjusted for line losses) are taken from the Powerstream EB-2014-0116 Draft Rate Order
Medium/Large Business (EB-2014-0116 Draft Rate Order, Schedule 4-2, Page 6): GS 50-999 customer, consumption 150,000 kWh, loss factor 3.76%
Large Industrial (EB-2014-0116 Draft Rate Order, Schedule 4-2, Page 8): Large Use customer, consumption 4,500,000 kWh, loss factor 1.87%

2 Ex.N3-1-1 Table 1, line 9.

3 Ex. N3-1-1_Table 1, Line 11

4 Ex. N3-1-1_Table 1, Line 8

UNDERTAKING J20.2

Undertaking

To provide a simplified calculation of the impact on hydroelectric revenue requirement if ROE is updated from 9.33% to 8.78% assuming the I-factor is held constant.

Response

The impact on the regulated hydroelectric revenue requirement if ROE is updated from 9.33% to 8.78% and the I-factor is held constant is approximately $25M per year over the IR period (assuming that all other components of the revenue requirement are held at the EB-2013-0321 approved amounts). OPG notes that this calculation is simplistic as OPG has not rebased the hydroelectric payment amounts since EB-2013-0321.

UNDERTAKING J20.3

Undertaking

To provide the revenue requirement impact over the five years for OPG to achieve 2014 median reflected in Hackett report for its Finance benchmark.

Response

Chart 1 below provides the mathematical calculation of the estimated nuclear revenue requirement (cost) impact against the 2014 median value for Finance in each of the 5 years of the IR Term. This undertaking response also incorporates Undertaking J20.4, which is a similar request for the mathematical calculation of the ECS cost impact, shown in Chart 1. For completeness, Chart 1 also provides the mathematical calculation of the estimated nuclear revenue requirement impact if IT and HR cost categories were similarly adjusted to achieve the 2014 median result. This provides a comprehensive view across all benchmarked groupings that were part of the Hackett study. In Chart 1, negative values are costs above the median and positive values are costs below the median.

For Finance, ECS and HR, these calculations are based on the 2017-2021 annual forecast OPG values provided in Ex. L-6.7-1 Staff-169 and Ex. L-6.7-1 Staff-170. As noted in Ex. L-6.7-1 Staff-169 (c), OPG does not forecast IT End Users. As such, also shown in Chart 2 below, OPG conservatively used the nuclear portion of the number of IT End Users reflected in the Hackett cost benchmarking study for 2014.

Chart 1
Revenue Requirement Impact - Corporate Cost Benchmarking ('$M)

	2017	2018	2019	2020	2021	Total IR Period
Finance	$ (4)	$ (4)	$ (5)	$ (2)	$ (4)	$ (19)
ECS	$ (62)	$ (62)	$ (63)	$ (58)	$ (62)	$ (307)
HR Cost	$ 6	$ 6	$ 6	$ 5	$ 4	$ 27
IT Cost	$ 75	$ 79	$ 79	$ 80	$ 81	$ 395
Total	$ 15	$ 19	$ 17	$ 25	$ 20	$ 95

Chart 2 below provides the four 2014 comparator median values and the forecast values for OPG over the IR term.

Chart 2

Annual Forecast information

	2014 Median	2017	2018	2019	2020	2021
Finance as a %	0.66	0.78	0.78	0.81	0.71	0.77
ECS as a %	1.07	2.84	2.85	2.95	2.58	2.81
HR per employee	$3,350	$2,659	$2,661	$2,695	$2,781	$2,839
IT Cost per End User	14,995	8,202	7,897	7,816	7,734	7,652

As noted by Mr. Mauti at Tr. Vol. 20, p. 26, lines 13 to 21 and p. 28, lines 22 to 24, this mathematical computation is not a benchmarking exercise. For instance, as noted in Ex. L-6.7-1 Staff-169 and Ex. L-6.7-1 Staff-170, the OPG values used represent an estimate based on information available to OPG in the normal course of business, not having been vetted against Hackett Group's specific taxonomy. Moreover, it is reasonable to expect the peer median value to change over a period of up to 7 years, from 2014 to 2021. In OPG's view, using a static median does not represent a valid comparison. It is likely that inflationary cost pressures would increase the median value over this period. This is consistent with Hackett's approach of escalating peer performance by 2% per year, from 2010 to 2014, in their study (Ex. F3-1-1, Att. 1, p. 6).

Understanding the drivers around a comparison of the company's position to the median for any benchmarked cost category is necessary for the appropriate interpretation of the benchmarking results. The discussion by Mr. Mauti at Tr. Vol. 21, p. 127, line 8 through p. 130, line 26 is an example of such considerations with respect to the ECS benchmarking results.

UNDERTAKING J20.4

Undertaking

To provide the cost impact over the five years for OPG to achieve 2014 median reflected in Hackett report for the ECS benchmark.

Response

Please refer to J20.3.

UNDERTAKING J20.5

Undertaking

To provide, on an order of magnitude, if the final negotiated less payments for 700 University track to budgeted amounts in the 2016-2018 Business Plan.

Response

Please see Tr. Vol. 20, p. 41, lines 22-28, p. 42, lines 1-13.

UNDERTAKING J20.6

Undertaking

TO CONFIRM WHETHER THERE IS AN OM&A COMPONENT EMBEDDED IN THE REFRENCE AMOUNT APPROVED IN EB-2013-0321 FOR THE HYDRO CRVA

Response

OPG confirms that an annual average of $0.1M in OM&A removal costs related to CRVA-eligible projects is embedded in the regulated hydroelectric base rates approved in EB-2013-0321.

UNDERTAKING J20.7

Undertaking

To show in Ex. C2-1-2, Chart 3 the consideration of income tax impacts

Response

This undertaking followed an exchange between Mr. Buonaguro and Mr. Kogan at Tr. Vol. 20, p. 100, line 6 to p. 102, line 27, in relation to income tax impacts associated with the comparison of estimated pre-tax amounts collected from ratepayers for nuclear liabilities for the period from April 1, 2008 to December 31, 2016 and the pre-tax amounts expended by OPG on nuclear liabilities in the form of segregated fund contributions and internally funded expenditures during that period, as shown in Ex. C2-1-2, Chart 3. In this response, OPG provides, in Charts 1-3 below, a comparison of these amounts on an after-tax basis.[1] This information is presented for the period from April 1, 2005 to December 31, 2021 covered by Ex. C2-1-2 and related Ex. J20.8. Specifically, Charts 1-3 below correspond to the pre-tax comparisons in Ex. C2-1-2, Chart 3 and 4 for the April 1, 2008 to December 31, 2016 and April 1, 2005 to March 31, 2008 periods, respectively, and in Ex. J20.8, Chart 1 for the 2017-2021 period.

Chart 1 indicates that the estimated after-tax amounts recovered over the period from April 1, 2008 to December 31, 2016 are lower than the after-tax amounts expended by OPG by approximately $7M (line 14) for the prescribed facilities and are higher by approximately $115M (line 24) for the Bruce facilities, for a net overall excess of amounts recovered over amounts expended of approximately $108M (line 26).

For the period from April 1, 2005 to March 31, 2008, at line 26, Chart 2 indicates that the after-tax proxy amounts collected from ratepayers through interim rates set by the Province are in the order of $1B lower than the after-tax amounts expended by OPG (specifically, $262M for the prescribed facilities at line 12 and $732M for the Bruce facilities at line 24).

For the 2017-2021 period, Chart 3 indicates that the after-tax amounts proposed for recovery (or recording in deferral and variance accounts) are lower than the after-tax amounts projected to be expended by OPG by approximately $475M for the prescribed

[1] The estimated amounts presented in this response represent the net value to OPG of the difference between after-tax amounts collected from ratepayers and after-tax amounts expended for nuclear liabilities for the applicable periods, excluding any time value of money considerations. In order to convert this into a hypothetical amount that would need to be exchanged between ratepayers and OPG so as to bring this difference to zero, these amounts would need to be grossed-up for taxes at the tax rate in effect during the period of such an exchange, currently at 25% and therefore resulting in a gross-up factor of 25%/(1-25%).

facilities (line 12) and are higher by approximately $793M for the Bruce facilities (line 22), for a net overall excess of amounts to be recovered over amounts to be expended of approximately $317M (line 24).

Over the full period from April 1, 2005 to December 31, 2021, the estimated after-tax amounts collected would be lower than the after-tax amounts expended by approximately $744M for the prescribed facilities and higher by approximately $176M for the Bruce facilities, for a net “shortfall” in amounts collected of approximately $568M. As of December 31, 2016, this “shortfall” stands at approximately $885M.

Chart 1
After-Tax Amounts Collected Versus Amounts Expended for Nuclear Liabilities ($M)
April 1, 2008 to December 31, 2016[2]

Line No.	Description	Apr 1 to Dec 31 2008	2009	2010	Jan 1 to Feb 28 2011	Mar 1 to Dec 31 2011	2012	2013	Jan 1 to Oct 31 2014	Nov 1 to Dec 31 2014	2015	2016	Total
	Prescribed Facilities												
1	**Total Amounts Recovered (pre-tax)** (Ex. C2-1-2, Chart 3, line 5)	147.4	192.4	190.5	36.6	113.8	286.3	208.6	180.7	37.0	198.5	157.0	1,748.8
2	**Reduction in Regulatory Income Taxes for Forecast Contributions to Segregated Funds and Forecast Internally Funded Expenditures on Nuclear Liabilities**	(32.1)	(58.6)	(48.2)	(7.3)	(49.8)	(43.9)	(43.2)	(51.0)	(10.7)	(63.5)	(63.8)	(472.1)
3	**(Under)/Over Recovery Due to Differences Between Approved and Actual Nuclear Production**	2.4	4.2	4.4	(0.4)	3.1	1.7	5.3	3.2	(0.4)	4.4	3.0	31.0
4	**Total Reduction in Regulatory Income Taxes** (line 2 + line 3)	(29.7)	(54.4)	(43.8)	(7.7)	(46.7)	(42.2)	(37.9)	(47.8)	(11.0)	(59.1)	(60.8)	(441.1)
5	**Regulatory Income Taxes on Amounts Recovered** ((line 1 + line 4) x tax rate / (1-tax rate))	54.1	62.0	59.9	10.4	24.2	81.4	56.9	44.3	8.6	46.5	32.1	480.4
6	**Total Regulatory Income Taxes** (line 4 + line 5)	24.5	7.7	16.1	2.7	(22.5)	39.1	19.0	(3.5)	(2.4)	(12.6)	(28.7)	39.3
7	**Total Amounts Recovered (after-tax)** (line 1 + line 6)	171.8	200.1	206.6	39.4	91.3	325.4	227.7	177.2	34.6	185.9	128.3	1,788.0
8	**Total Amounts Expended (pre-tax)** (Ex. C2-1-2, Chart 3, line 8)	76.3	188.3	210.4	35.5	178.2	181.0	158.1	186.7	50.2	257.9	267.0	1,789.6
9	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities** (line 8 x tax rate)	(24.0)	(58.4)	(61.0)	(9.4)	(47.2)	(45.3)	(39.5)	(46.7)	(12.5)	(64.5)	(66.7)	(475.3)
10	**Income Taxes on Amounts Recovered** (line 7 x tax rate)	54.1	62.0	59.9	10.4	24.2	81.4	56.9	44.3	8.6	46.5	32.1	480.4
11	**Total Income Taxes** (line 9 + line 10)	30.1	3.6	(1.1)	1.0	(23.0)	36.1	17.4	(2.4)	(3.9)	(18.0)	(34.7)	5.1
12	**Total Amounts Expended (after-tax)** (line 8 + line 11)	106.4	191.9	209.3	36.5	155.2	217.1	175.5	184.3	46.3	239.9	232.3	1,794.7
13	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)** (line 1 - line 8)	71.1	4.1	(19.9)	1.2	(64.4)	105.3	50.5	(6.0)	(13.2)	(59.4)	(110.0)	(40.9)
14	**Excess of Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)** (line 7 - line 12)	65.4	8.1	(2.7)	2.9	(63.9)	108.3	52.2	(7.2)	(11.7)	(54.0)	(104.0)	(6.7)
	Bruce Facilities												
15	**Actual Bruce Lease Net Revenues Impact** (Ex. C2-1-2, Chart 3, line 10)	311.5	(32.6)	(68.6)	(8.5)	89.5	70.5	142.4	81.2	20.5	173.6	231.6	1,011.2
16	**Regulatory Income Tax Impact** (line 15 x tax rate / (1 - tax rate))	143.2	(14.6)	(28.0)	(3.1)	32.3	23.5	47.5	27.1	6.8	57.9	77.2	369.7
17	**Total Amounts Recovered (after-tax)** (line 15 + line 16)	454.7	(47.2)	(96.6)	(11.6)	121.8	94.0	189.9	108.3	27.4	231.5	308.8	1,380.9
18	**Total Amounts Expended (pre-tax)** (Ex. C2-1-2, Chart 3, line 13)	331.1	237.9	133.2	24.2	125.4	130.5	145.5	15.0	14.3	21.3	74.1	1,252.5
19	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Internally Funded Expenditures** (line 18 x tax rate)	(104.3)	(73.7)	(38.6)	(6.4)	(33.2)	(32.6)	(36.4)	(3.8)	(3.6)	(5.3)	(18.5)	(356.5)
20	**Income Taxes on Amounts Recovered** (line 17 x tax rate)	143.2	(14.6)	(28.0)	(3.1)	32.3	23.5	47.5	27.1	6.8	57.9	77.2	369.7
21	**Total Income Taxes** (line 19 + line 20)	38.9	(88.4)	(66.6)	(9.5)	(1.0)	(9.1)	11.1	23.3	3.3	52.6	58.7	13.3
22	**Total Amounts Expended (after-tax)** (line 18 + line 21)	370.0	149.5	66.6	14.7	124.4	121.4	156.6	38.3	17.6	73.8	132.8	1,265.7
23	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)** (line 15 - line 18)	(19.6)	(270.5)	(201.8)	(32.7)	(35.9)	(60.0)	(3.0)	66.2	6.2	152.4	157.5	(241.3)
24	**Excess of Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)** (line 17 - line 22)	84.7	(196.8)	(163.2)	(26.3)	(2.7)	(27.4)	33.3	70.0	9.8	157.7	176.0	115.2
25	**Total Excess of Amounts Recovered over Amounts Expended (pre-tax)** (line 13 + line 23)	51.5	(266.4)	(221.7)	(31.5)	(100.3)	45.3	47.5	60.2	(7.0)	92.9	47.5	(282.1)
26	**Total Excess of Amounts Recovered over Amounts Expended (after-tax)** (line 14 + line 24)	150.1	(188.6)	(165.9)	(23.4)	(66.6)	80.9	85.5	62.8	(1.9)	103.6	72.0	108.5

Note 1: For the purposes of simplifying this analysis, regulatory income taxes on amounts recorded in the Bruce Lease Net Revenues Variance Accounts are assumed to be collected from, or repaid to, ratepayers in the period the variance entry arises, at the tax rate of that period.

[2] The following tax rates in effect during the corresponding periods were applied in the analysis: 2008 – 31.50%, 2009 – 31.00%, 2010 – 29.00%, 2011 – 26.50%, 2012 onwards – 25.00%.

Chart 2
Proxy After-Tax Amounts Collected Versus Expended for Nuclear Liabilities ($M)
April 1, 2005 to March 31, 2008[3]

Line No.	Description	Reference	Apr 1 to Dec 31 2005	2006	2007	Jan 1 to Mar 31 2008	Total
	Prescribed Facilities						
1	**Pre-tax Proxy Amounts Recovered**	Ex. C2-1-2, Chart 4, line 1	132	156	225	53	566
2	**Reduction in Proxy Regulatory Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities**	line 6 x tax rate	(72)	(116)	(79)	(13)	(281)
3	**Regulatory Income Taxes on Proxy Amounts Recovered**	(line 1 + line 2) x tax rate / (1-tax rate)	31	21	75	18	145
4	**Total Proxy Regulatory Income Taxes**	line 2 + line 3	(42)	(95)	(4)	5	(136)
5	**After-tax Proxy Amounts Recovered**	line 1 + line 4	90	61	221	57	429
6	**Total Amounts Expended (pre-tax)**	Ex. C2-1-2, Chart 4, line 4	212	340	233	43	828
7	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities**	line 6 x tax rate	(72)	(116)	(79)	(13)	(281)
8	**Income Taxes on Proxy Amounts Recovered**	line 5 x tax rate	31	21	75	18	145
9	**Total Income Taxes**	line 7 + line 8	(42)	(95)	(4)	5	(136)
10	**Total Amounts Expended (after-tax)**	line 6 + line 9	171	245	229	47	692
11	**Excess of Proxy Amounts Recovered over Amounts Expended - Prescribed Facilities (pre-tax)**	line 1 - line 6	(80)	(184)	(8)	10	(262)
12	**Excess of Proxy Amounts Recovered over Amounts Expended - Prescribed Facilities (after-tax)**	line 5 - line 10	(80)	(184)	(8)	10	(262)
	Bruce Facilities						
13	**Pre-tax Proxy Amounts Recovered**	Ex. C2-1-2, Chart 4, line 6	87	114	179	34	414
14	**Reduction in Proxy Regulatory Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities**	line 18 x tax rate	(59)	(85)	(207)	(37)	(388)
15	**Regulatory Income Taxes on Proxy Amounts Recovered**	(line 13 + line 14) x tax rate / (1-tax rate)	14	15	(14)	(2)	14
16	**Total Proxy Regulatory Income Taxes**	line 14 + line 15	(45)	(69)	(221)	(39)	(374)
17	**After-tax Proxy Amounts Recovered**	line 13 + line 16	42	45	(42)	(5)	39
18	**Total Amounts Expended (pre-tax)**	Ex. C2-1-2, Chart 4, line 9	174	248	606	117	1,145
19	**Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Internally Funded Expenditures**	line 18 x tax rate	(59)	(85)	(207)	(37)	(388)
20	**Income Taxes on Proxy Amounts Recovered**	line 17 x tax rate	14	15	(14)	(2)	14
21	**Total Income Taxes**	line 19 + line 20	(45)	(69)	(221)	(39)	(374)
22	**Total Amounts Expended (after-tax)**	line 18 + line 21	129	179	385	79	771
23	**Excess of Proxy Amounts Recovered over Amounts Expended - Bruce Facilities (pre-tax)**	line 13 - line 18	(87)	(134)	(427)	(84)	(732)
24	**Excess of Proxy Amounts Recovered over Amounts Expended - Bruce Facilities (after-tax)**	line 17 - line 22	(87)	(134)	(427)	(84)	(732)
25	**Total Excess of Proxy Amounts Recovered over Amounts Expended (pre-tax)**	line 11 + line 23	(167)	(318)	(435)	(74)	(994)
26	**Total Excess of Proxy Amounts Recovered over Amounts Expended (after-tax)**	line 12 + line 24	(167)	(318)	(435)	(74)	(994)

[3] The following tax rates in effect during the corresponding periods were applied in the analysis: 2005 to 2007 – 34.12%, 2008 – 31.50%.

Chart 3
After-Tax Amounts Expected to Be Collected Versus Expended for Nuclear Liabilities ($M)
January 1, 2017 to December 31, 2021[4]

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	**Total Pre-tax Revenue Requirement Impact**	Ex. J20.8, Chart 1, line 3	152.1	147.9	156.6	144.3	78.8	679.7
2	**Reduction in Regulatory Income Taxes for Forecast Contributions to Segregated Funds and Forecast Internally Funded Expenditures on Nuclear Liabilities**	line 6 x tax rate	(58.9)	(61.2)	(53.7)	(58.5)	(56.5)	(288.8)
3	**Regulatory Income Taxes on Amounts Forecast to Be Recovered**	(line 1 + line 2) x tax rate / (1-tax rate)	31.1	28.9	34.3	28.6	7.5	130.3
4	**Total Regulatory Income Taxes**	line 2 + line 3	(27.8)	(32.3)	(19.4)	(29.9)	(49.0)	(158.5)
5	**Total After-tax Revenue Requirement Impact** *(Ex. J21.2, Chart 1, line 5)*	line 1 + line 4	124.2	115.6	137.2	114.3	29.8	521.3
6	**Total Amounts Forecast to Be Expended (pre-tax)**	Ex. J20.8, Chart 1, line 6	235.6	244.7	214.9	234.1	225.8	1,155.2
7	**Forecast Reduction in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities**	line 6 x tax rate	(58.9)	(61.2)	(53.7)	(58.5)	(56.5)	(288.8)
8	**Income Taxes on Amounts Forecast to Be Recovered**	line 5 x tax rate	31.1	28.9	34.3	28.6	7.5	130.3
9	**Total Forecast Income Taxes**	line 7 + line 8	(27.8)	(32.3)	(19.4)	(29.9)	(49.0)	(158.5)
10	**Total Amounts Forecast to Be Expended (after-tax)**	line 6 + line 9	207.8	212.5	195.5	204.2	176.8	996.7
11	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Prescribed Facilities (pre-tax)**	line 1 - line 6	(83.5)	(96.8)	(58.3)	(89.8)	(147.0)	(475.4)
12	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Prescribed Facilities (after-tax)**	line 5 - line 10	(83.5)	(96.8)	(58.3)	(89.8)	(147.0)	(475.4)
	Bruce Facilities							
13	**Total Bruce Lease Net Revenues Impact**	Ex. J20.8, Chart 1, line 11	144.8	140.5	146.3	154.0	150.9	736.5
14	**Regulatory Income Tax Impact**	line 13 x tax rate / (1-tax rate)	48.3	46.8	48.8	51.3	50.3	245.5
15	**Total After-tax Revenue Requirement Impact** *(Ex. J21.2, Chart 1, line 8)*	line 13 + line 14	193.1	187.4	195.1	205.3	201.2	982.1
16	**Total Amounts Forecast to Be Expended (pre-tax)**	Ex. J20.8, Chart 1, line 14	(16.0)	(9.2)	2.4	(21.2)	(31.1)	(75.1)
17	**Forecast Increase (Reduction) in Income Taxes for Contributions to Segregated Funds and Internally Funded Expenditures on Nuclear Liabilities**	line 16 x tax rate	4.0	2.3	(0.6)	5.3	7.8	18.8
18	**Income Taxes on Amounts Recovered**	line 15 x tax rate	48.3	46.8	48.8	51.3	50.3	245.5
19	**Total Income Taxes**	line 17 + line 18	52.3	49.1	48.2	56.6	58.1	264.3
20	**Total Amounts Forecast to Be Expended (after-tax)**	line 16 + line 19	36.3	40.0	50.6	35.4	27.0	189.2
21	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Bruce Facilities (pre-tax)**	line 13 - line 16	160.8	149.7	143.9	175.2	182.0	811.6
22	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Bruce Facilities (after-tax)**	line 15 - line 20	156.8	147.4	144.5	169.9	174.2	792.9
23	**Total Excess of Amounts Proposed for Recovery over Forecast Amounts Expended (pre-tax)**	line 11 + line 21	77.3	52.9	85.7	85.3	35.0	336.2
24	**Total Excess of Amounts Proposed for Recovery over Forecast Amounts Expended (after-tax)**	line 12 + line 22	73.3	50.6	86.2	80.0	27.2	317.4

[4] A tax rate of 25.00% was applied in this analysis, consistent with Ex. F4-2-1 Table 3a, line 29.

UNDERTAKING J20.8

Undertaking

To provide forecast information for the 2017-2021 period for nuclear liabilities that reflects updated contribution amounts as well as other credits from true up to year end adjustment for nuclear liabilities, similar to Chart 3 of Ex. C2-1-2. To also include tax impacts.

Response

Chart 1 below presents a comparison of amounts proposed to be collected from ratepayers (or expected to be recorded in deferral and variance accounts for future disposition) for nuclear liabilities, before taxes, for the 2017-2021 period and amounts projected to be expended by OPG on nuclear liabilities in the form of fund contributions and internally funded expenditures during that period. This information is presented in the same format as Ex. C2-1-2 Chart 3.

The tax impacts associated with this information are being provided in response to undertaking J20.7, along with the tax impacts for the 2008-2016 period.

Chart 1
Amounts Expected to Be Collected Versus Expended for Nuclear Liabilities ($M)
January 1, 2017 to December 31, 2021

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	**Pre-tax Revenue Requirement Impact per Ex. N1-1-1**	Ex. C2-1-2, Chart 1, line 1	167.1	162.6	173.4	158.2	89.1	750.5
2	**Impact of Differences Between Projected and Actual Impact of 2017 ONFA Reference Plan to be Recorded in Nuclear Liability Deferral Account**		(15.0)	(14.7)	(16.8)	(13.9)	(10.3)	(70.7)
3	**Total Pre-tax Revenue Requirement Impact**	line 1 + line 2	152.1	147.9	156.6	144.3	78.8	679.7
4	**Forecast Contributions to Segregated Funds per 2017 ONFA Contribution Schedule**	Ex. C2-1-2, Chart 1A, line 2	102.5	102.5	102.5	102.5	102.5	512.5
5	**Forecast Internally Funded Expenditures on Nuclear Liabilities**	Ex. N1-1-1, Table 3: line 15 - line 8	133.1	142.2	112.4	131.6	123.3	642.7
6	**Total Amounts Forecast to be Expended**	line 4 + line 5	235.6	244.7	214.9	234.1	225.8	1,155.2
7	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Prescribed Facilities (pre-tax)**	line 3 - line 6	(83.5)	(96.8)	(58.3)	(89.8)	(147.0)	(475.4)
	Bruce Facilities							
8	**Bruce Lease Net Revenues Impact per Ex. N1-1-1**	Ex. C2-1-2, Chart 1, line 6	156.4	150.4	153.1	157.7	148.6	766.2
9	**Impact of Approved Contribution Schedule on Segregated Fund Earnings to be Recorded in Bruce Lease Net Revenues Variance Account**	Ex. C2-1-2, Chart 1A, line 9	2.0	6.0	10.2	14.4	18.6	51.2
10	**Impact of Differences Between Projected and Actual Impact of 2017 ONFA Reference Plan to be Recorded in Bruce Lease Net Revenues Variance Account**		(13.6)	(15.9)	(17.0)	(18.1)	(16.3)	(80.9)
11	**Total Bruce Lease Net Revenues Impact**	line 8 + line 9 + line 10	144.8	140.5	146.3	154.0	150.9	736.5
12	**Forecast Contributions to Segregated Funds per 2017 ONFA Contribution Schedule**		(102.5)	(102.5)	(102.5)	(102.5)	(102.5)	(512.5)
13	**Forecast Internally Funded Expenditures on Nuclear Liabilities**	Ex. N1-1-1, Table 4: line 15 - line 8	86.5	93.3	104.9	81.3	71.4	437.4
14	**Total Amounts Forecast to be Expended**	line 12 + line 13	(16.0)	(9.2)	2.4	(21.2)	(31.1)	(75.1)
15	**Excess of Amounts Proposed for Recovery over Forecast Amounts Expended - Bruce Facilities (pre-tax)**	line 11 - line 14	160.8	149.7	143.9	175.2	182.0	811.6
16	**Total Excess of Amounts Proposed for Recovery over Forecast Amounts Expended (pre-tax)**	line 7 + line 15	77.3	52.9	85.7	85.3	35.0	336.2

UNDERTAKING J20.9

Undertaking

To produce any further final Hackett Reports.

Response

There are none.

UNDERTAKING J20.10

Undertaking

(A) To update Chart 1 on page 1 of the AMPCO Compendium (Ex. K20.4); (B) To update the chart on page 2 of the AMPCO Compendium (Ex. K20.4).

Response

The requested charts are provided in Attachment 1, Table 1 and Table 2. As clarified through the exchange at Tr. Vol. 20, p. 121, line 5 to p. 122, line 5 preceding this undertaking, these charts reflect the actual 2016 in-service additions and the forecast 2017-2021 annual in-service additions and depreciation expense per the pre-filed evidence, all of which have been adjusted for the removal of the Heavy Water Storage and Drum Handling Facility Project ("D2O Project") in-service additions. Table 2 also reflects the actual year-end 2016 asset retirement cost adjustment, a reduction of $258.3M, resulting from the 2017 ONFA Reference Plan update, and associated 2017-2021 annual depreciation expense impacts.[1]

OPG does not believe that the selective update provided by this undertaking would provide a reasonable basis on which to establish the nuclear rate base values for the 2017-2021 period (Tr. Vol. 21, p.4, line 24 to p. 6, line 16). The information requested in the undertaking shows the effect of a variance between forecast and actual 2016 in-service amounts without considering changes in the forecast in-service amounts over the full period to 2021, including those due to projects that were planned to come into service in 2016 moving into 2017. For example, Ex. J14.1 notes that, for Nuclear Operations capital, $70.3M that was planned for 2016 was placed in service in Q1 2017. As well, as part of the Darlington Refurbishment Program ("DRP"), the Containment Filtered Venting System Project has been placed in service in 2017 and the Third Emergency Power Generator Project will be placed in service shortly. These two projects were originally planned to come in service in 2016 at a projected total of approximately $200M.[2]

As discussed in Ex. J21.1, OPG continues to propose that the pre-filed rate base values be approved in this application, subject to the removal of the D2O Project per Ex. N2-1-1 and the inclusion of the year-end 2016 asset retirement cost adjustment arising from

[1] This asset retirement cost adjustment underpins the 2017-2021 nuclear liabilities' revenue requirement impact for the prescribed facilities detailed in Ex. J21.2. The amount of this adjustment differs from $237.9M shown at Ex. N1-1-1, Table 3, col. (a), line 22 (and detailed at Ex. N1-1-1, Table 5) because Ex. N1-1-1 reflected projected impacts of the 2017 ONFA Reference Plan update, which were determined prior to the end of 2016 for the purposes of the 2017-2019 Business Plan.

[2] Ratepayers are kept whole for any change in DRP in-service amounts through the Capacity Refurbishment Variance Account.

the 2017 ONFA Reference Plan update. Ex. J21.1 also provides OPG's current best-efforts view of 2017-2021 nuclear net plant rate base values, including both year-end 2016 actual results and a more recent outlook for Nuclear Operations and Support Services in-service capital over the IR Term. As discussed in Ex. J21.1, this current view demonstrates that the pre-filed rate base values remain reasonable.

Numbers may not add due to rounding.

Table 1
Forecast Nuclear In-Service Capital Additions
(Updated Ex. B1-1-1 Chart 1 for 2016 Actuals and Removal of D2O Project In-Service Additions)

	Reference for 2017-2021	Actual 2016	2017	2018	2019	2020	2021
Nuclear Operations capital projects[1]	Ex. D2-1-3 Table 4, line 17 & 26	292.0	389.0	315.2	239.3	300.4	215.6
Darlington Refurbishment Program	Ex. N2-1-1 Table 3, line 12 & 17	164.4	8.5	8.9	0.0	4,809.2	0.4
Support Services capital projects entering rate base	Nuclear Portion of Ex. D3-1-2 Table 5, lines 7, 9, 13 & 15	8.9	8.1	18.0	5.0	5.0	5.0
Total nuclear in-service additions, excluding ARC	**Ex. B3-3-1 Tables 1 & 2, col. (b)**	**465.3**	**405.6**	**342.1**	**244.3**	**5,114.7**	**221.1**

[1] Actual 2016 as shown in Ex. J14.1, Att. 1, Table 1, col. (e), line 17.

Numbers may not add due to rounding.

Filed: 2017-04-24
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J20.10
Attachment 1
Table 2

Table 2
Prescribed Facility Rate Base - Nuclear ($M)
(Updated Ex. B3-1-1 Table 1 for 2016 Actuals and Removal of 2016-2021 D2O Project In-Service Additions)
Years Ending December 31, 2013 to 2021

Line No.	Prescribed Facility	2013 Actual			2014 Actual			2015 Actual		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	801.9	294.8	507.1	870.5	326.9	543.6	939.1	359.6	579.5
2	**Darlington Refurbishment Program**	61.3	1.1	60.2	125.9	4.7	121.2	203.1	10.5	192.6
3	**Pickering NGS**	2,008.1	1,145.8	862.3	2,094.3	1,279.0	815.3	2,170.9	1,422.5	748.4
4	**Nuclear Support Divisions**[1]	332.1	228.1	104.1	354.2	255.6	98.5	369.3	282.6	86.8
5	**Nuclear - Excluding Asset Retirement Costs**	3,203.5	1,669.9	1,533.6	3,444.8	1,866.2	1,578.7	3,682.5	2,075.1	1,607.4
6	**Asset Retirement Costs**	2,839.2	1,369.0	1,470.2	2,839.2	1,449.7	1,389.4	2,839.2	1,530.5	1,308.7
7	**Total**	6,042.7	3,038.9	3,003.8	6,284.0	3,315.9	2,968.1	6,521.7	3,605.6	2,916.1

Line No.	Prescribed Facility	2016 Actual			2017 Plan			2018 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**Darlington NGS**	1,152.4	394.9	757.5	1,383.7	436.6	947.1	1,647.0	484.4	1,162.6
9	**Darlington Refurbishment Program**	377.0	22.2	354.7	463.4	40.0	423.5	472.1	59.0	413.1
10	**Pickering NGS**	2,235.2	1,570.7	664.5	2,311.8	1,745.6	566.2	2,397.9	1,957.1	440.8
11	**Nuclear Support Divisions**[1]	384.0	307.2	76.7	399.5	332.0	67.5	415.2	357.3	57.9
12	**Nuclear - Excluding Asset Retirement Costs**	4,148.6	2,295.1	1,853.5	4,558.4	2,554.1	2,004.3	4,932.2	2,857.9	2,074.3
13	**Asset Retirement Costs**[2]	2,421.7	1,596.0	825.7	2,163.3	1,658.2	505.1	2,163.3	1,732.3	431.0
14	**Total**	6,570.2	3,891.1	2,679.2	6,721.7	4,212.3	2,509.4	7,095.6	4,590.2	2,505.3

Line No.	Prescribed Facility	2019 Plan			2020 Plan			2021 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
15	**Darlington NGS**	1,887.0	538.5	1,348.5	2,142.6	598.3	1,544.3	2,361.2	664.2	1,697.0
16	**Darlington Refurbishment Program**	476.6	78.3	398.3	4,672.8	162.2	4,510.6	5,286.0	319.9	4,966.1
17	**Pickering NGS**	2,434.6	2,182.1	252.5	2,442.1	2,412.0	30.1	2,474.7	2,555.2	(80.6)
18	**Nuclear Support Divisions**[1]	427.3	379.4	47.9	439.0	399.3	39.8	451.0	418.8	32.2
19	**Nuclear - Excluding Asset Retirement Costs**	5,225.5	3,178.3	2,047.2	9,696.6	3,571.7	6,124.9	10,572.8	3,958.1	6,614.7
20	**Asset Retirement Costs**[2]	2,163.3	1,806.5	356.8	2,163.3	1,880.6	282.7	2,163.3	1,921.5	241.8
21	**Total**	7,388.8	4,984.8	2,404.0	11,859.9	5,452.4	6,407.6	12,736.1	5,879.6	6,856.5

Notes:
1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
2 Starting in 2017, updated to reflect the change in asset retirement costs $(258.3M) recorded on December 31, 2016 as a result of the 2017 ONFA Reference Plan update, and associated annual depreciation expense impacts.

UNDERTAKING J20.11

Undertaking

To produce a high level estimate of the revenue requirement and Payment Amounts impacts if Unit 2 not in-service in test period.

Response

The total estimated impact on the nuclear revenue requirement of the hypothetical scenario that removes the proposed Darlington Unit 2 refurbishment capital in-service amounts in 2020 and 2021 is a decrease of approximately $721M over the 2017-2021 IR Term. Including the impact on the carryback of regulatory tax losses between individual years of the IR Term, the estimated annual impacts comprising the total impact of $721M are as follows: an increase of approximately $33M in 2017, $59M in 2018, and $78M in 2019, and a decrease of approximately $421M in 2020 and $470M in 2021, as shown in Chart 1 below. The increases in revenue requirement in 2017-2019 relate to removal of capital cost allowance tax deductions.

Chart 2 and Chart 3 below provide additional details requested on the resulting rate base changes, in the same format as Ex. N2-1-1.

Chart 1
Nuclear Revenue Requirement Impact of Removing Forecast Darlington Unit 2 Refurbishment In-Service Amounts in 2020 and 2021

Line No.		2017	2018	2019	2020	2021	Total
1	Net Plant Rate Base Decrease[1]	-	-	-	(4,127.1)	(4,597.5)	
2	Weighted Average Cost of Capital[2]	6.80%	6.66%	6.63%	6.61%	6.60%	
3	Cost of Capital Amount (line 1 x line 2)	-	-	-	(272.7)	(303.5)	(576.2)
4	Decrease in Depreciation Expense[3]	-	-	-	(128.9)	(147.3)	(276.2)
5	Capital Cost Allowance	129.2	189.3	247.3	249.7	229.7	1,045.2
6	Net Increase (Decrease) in Regulatory Taxable Income[4]	129.2	189.3	247.3	(56.8)	(115.4)	393.6
7	Income Tax Impact (line 6 x 25% / (1 - 25%))	43.1	63.1	82.4	(18.9)	(38.5)	131.2
8	Regulatory Loss Carryback	11.5	(31.1)	(5.5)	-	25.1	-
9	**Total Revenue Requirement** (line 3 + line 4 + line 7 + line 8)	**54.5**	**32.0**	**77.0**	**(420.5)**	**(464.1)**	**(721.2)**

[1] From Chart 2, line 9
[2] As shown in Ex. N2-1-1 Chart 1, line 2
[3] As shown in Ex. L-2.2-1 Staff-9, Att. 1
[4] Calculated as: line 1 x 49% proposed equity thickness x 8.78% ROE value + line 4 + line 5

Chart 2
Impact of Forecast Darlington Unit 2 Refurbishment In-Service Amounts on Net Plant Rate Base

Line No.		Reference	2017	2018	2019	2020	2021
1	Gross Plant In-service - Opening Balance		-	-	-	-	4,799.8
2	Gross Plant In-service - Additions	Ex. D2-2-10, Table 2, line 1	-	-	-	4,799.8	0.4
3	Gross Plant In-service - Closing Balance	line 1 + line 2	-	-	-	4,799.8	4,800.2
4	Accumulated Depreciation - Opening Balance		-	-	-	-	128.9
5	Accumulated Depreciation - Additions	Ex. L2.2-1 Staff-9, Att 1	-	-	-	128.9	147.3
6	Accumulated Depreciation - Closing Balance	line 4 + line 5	-	-	-	128.9	276.2
7	Net Plant In-service - Opening Balance	line 1 + line 4	-	-	-	-	4,670.9
8	Net Plant In-service - Closing Balance	line 3 - line 6	-	-	-	4,670.9	4,524.0
9	**Net Plant Rate Base Impact**	Note 1	**-**	**-**	**-**	**4,127.1**	**4,597.5**

1 As the in-service addition of $4,777.7M for the return to service of the refurbished Darlington Unit 2 is forecast in mid February 2020 (see Ex. B3-3-1, Table 2, Note 3), it is assigned a 10.5/12 weighting in that year. Therefore, the 2020 net plant rate base amount is calculated as 10.5/12 x 4,777.7M + ((line 2 - $4,777.7M) - (line 4 - line 6))/2. For 2021, the net plant rate base amount is calculated as (line 7 + line 8)/2. These net plant rate base values are also found at Ex. L-4.3-2 AMPCO-077, Att. 1, Table 1a, line 1b.

Chart 3
Changes in Nuclear Net Rate Base

Line No.		Reference	2017	2018	2019	2020	2021
	N2 Update						
1	Darlington Refurbishment Program - Net Plant Rate Base	N2-1-1 Chart 3, line 4	611.9	601.5	586.7	4,699.1	5,154.5
2	Total Nuclear Net Plant Rate Base	N2-1-1 Chart 3, line 5	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
3	Total Nuclear Rate Base	N2-1-1 Chart 3, line 6	3,627.9	3,606.9	3,476.2	7,453.8	7,887.0
	N2 Update, Less 2020 &2021 Darlington Unit 2 Refurbishment In-Service Additions						
4	Darlington Refurbishment Program - Net Plant Rate Base		611.9	601.5	586.7	571.9	557.0
5	Total Nuclear Net Plant Rate Base		2,916.4	2,909.2	2,804.7	2,678.0	2,654.9
6	Total Nuclear Rate Base		3,627.9	3,606.9	3,476.2	3,326.7	3,289.4
7	**Nuclear Rate Base Decrease**	line 6 - line 3	**(0.0)**	**(0.0)**	**(0.0)**	**(4,127.1)**	**(4,597.5)**

OPG does not believe that the undertaking postulates a reasonable scenario. As OPG indicated during the hearing, OPG is now ten years into the Darlington Refurbishment Program (DRP), and has completed both the Initiation and Definition Phases of the DRP. OPG has put tremendous effort into preparing the Release Quality Estimate for the DRP and the Unit 2 Execution Estimate. These estimates are high confidence estimates with a high degree of cost and schedule certainty and with adequate contingency based on the class of estimate. In addition, independent experts have given testimony that OPG has reasonably and prudently prepared for the DRP (see, for example, Ex. D2-2-11, p. 8 and Ex. M1, p. 6). Now that OPG is already approximately $2.9B into the program, OPG believes that it has completed enough work and at a level of quality to adequately support that the cost and schedule estimates set out in its Application are reasonable and should be reflected in the 2017-2021 revenue requirement set in this proceeding (see Tr. Vol. 1, p. 67).

UNDERTAKING J20.12

Undertaking

To provide the nuclear allocation portion of Purchased Services – Support Services directly from the Nuclear Business and the DRP.

Response

The 2016 (actual), and 2017-2021 forecast of spend allocated to the Nuclear business unit in purchased services for Support Services is displayed below in Chart 1.

Chart 1
Purchased Services - Support Services ($M)

2016	2017	2018	2019	2020	2021
112	109	106	107	106	106

The primary purchased service being the information technology outsource service contract with New Horizon System Solutions.

UNDERTAKING J20.13

Undertaking

TO PROVIDE THE CRVA AMOUNTS FUNDED IN RATES IN 2014 AND 2015 FOR THE WATER AND SEWER PROJECT

Response

The average annual amount funded in the EB-2013-0321 nuclear payment amounts for the Water and Sewer Project is $3.8M, as shown on line 8 of Chart 1 below.[1] This amount is determined based on in-service additions totaling $27.2M and the resulting net plant rate base of $20.8M for 2014 and $26.4M for 2015 reflected in the EB-2013-0321 payment amounts.[2] The EB-2013-0321 payment amounts were effective November 1, 2014.

Chart 1
EB-2013-0321 Reference Plan Amount for the Water and Sewer Project

Line No.	$M	2014	2015	Avg. Annual Amounts
		(a)	(b)	(c) = (a) + (b) /2
	Forecast Capital Costs:			
1	Forecast Net Plant Rate Base[1]	20.8	26.4	
2	Weighted Average Cost of Capital[2]	6.86%	6.85%	
3	Cost of Capital (line 1 x line 2)	1.4	1.8	1.6
4	Forecast Depreciation[1]	0.4	0.6	0.5
5	Forecast Income Tax Impacts[3]	0.4	0.6	0.5
6	Total Forecast Capital Costs (line 3 through line 5)	2.3	3.0	2.6
7	Forecast Non-Capital Costs	2.4	-	1.2
8	**Revenue Requirement** (line 6 + line 7)	**4.7**	**3.0**	**3.8**

[1] As shown in EB-2013-0321 Ex. L4.9-1 Staff-48 Chart 1 and EB-2016-0152 Ex. L-9.1-1 Staff-210 Table 1.
[2] From EB-2013-0321 Payment Amounts Order , App. A, Table 6b, col. (c), line 6.
[3] Calculated as: ((line 1 x 45% x 9.30%) + line 4) x 25% / (1-25%).

[1] For consistency with other interrogatory responses, the revenue requirement impacts provided throughout this response do not reflect capital cost allowance ("CCA") tax deductions.
[2] The underpinning in-service additions, by year, were $5.0M in 2012 (actual), $10.0M in 2013 (forecast) and $12.2M in 2014 (forecast), as shown at EB-2013-0321 Ex. D2-2-1, section 7.2.2 and EB-2013-0321 Ex. D2-2-1, Table 3, line 4, cols. (k) and (l).

As at December 31, 2015, actual capital in service amounts totaled $43.7M ($5.0M in 2012, $15.8M in 2013, and $22.9M in 2014).[3] The net plant rate base amounts for 2014 and 2015 based on these actual in-service additions are $31.6M and $41.8M (Ex. L-9.1-1 Staff-210 Table 1).

The full revenue requirement impact of the Water and Sewer Project actual in-service capital from 2012 to October 31, 2014 was recorded in the Capacity Refurbishment Variance Account ("CRVA"), as the EB-2010-0008 payment amounts did not reflect any amounts for this project. For the period from November 1, 2014 to December 31, 2015, CRVA additions for the project were recorded relative to the annual reference value of $3.8M shown in Chart 1.

Amounts recorded in the CRVA to December 31, 2014 based on the above actual and reference amounts were approved by the OEB through the EB-2013-0321 and EB-2014-0370 proceedings. OPG is requesting the disposition of the $2.5M debit amount for the project recorded in the CRVA during 2015, as part of this Application. The derivation of the $2.5M debit addition is shown in Chart 2 below. This amount forms part of the 2015 nuclear CRVA additions detailed in Ex. H1-1-1 Table 11, as totaled at line 34 for the capital portion and line 17 for the non-capital portion of that table.

[3] The 2012 in-service amount can be found at EB-2013-0321 Ex. D2-2-1 Section 7.2.2, line 16; 2013 in-service amount can be found at EB-2013-0321 Ex. L-9.1-17 SEC-132 Att. 1, Table 12a, Table to Note 1. Note ++ and EB-2013-0321 Ex. L-4.7-2 AMPCO-020 (g); 2014 in-service amount can be found at EB-2016-0152 Ex. L-2.2-1 Staff-008 (a).

Chart 2
2015 CRVA Addition – Water and Sewer Project

Line No.	$M	2015
	Capital Addition to Variance Account	
1	Forecast Cost of Capital Amount[1]	1.6
2	Actual Net Plant Rate Base[2]	41.8
3	Weighted Average Cost of Capital[3]	6.85%
4	Actual Cost of Capital (line 1 x line 2)	2.9
5	Cost of Capital Variance (line 4 - line1)	1.2
6	Forecast Depreciation[1]	0.5
7	Actual Depreciation	1.6
8	Depreciation Variance (line7 - line 6)	1.1
9	Net Increase in Regulatory Taxable Income[4]	1.8
10	Income Tax Rate	25.00%
11	Income Tax Variance (line 9 x line 10 / (1-line 10)	0.6
12	Capital Addition to Variance Account Before Adjustment (line 5 + line 8 + line 11)	2.9
	Non-Capital Addition to Variance Account	
13	Forecast Non-Capital (OM&A) Costs[1]	1.2
14	Actual Non-Capital (OM&A) Costs	-
15	Non-Capital Addition to Variance Account Before Adjustment (lines 14 - line 13)	(1.2)
16	Less: EB-2013-0132 Impact Statement (Ex. N1) Adjustment	(0.8)
17	**Total Addition to Variance Account** (line 12 + line 15 - line 16)	**2.5**

[1] From Chart 1, col. (c)
[2] As shown in Ex. L-9.1-1 Staff-210, Table 1
[3] From EB-2013-0321 Payment Amounts Order, App. A, Table 6b, col. (c), line 6.
[4] Calculated as: line 2 x 45% x 9.30%, less Chart 1, col. (b) line 1 x 45% x 9.30%, plus line 8

The proposed rate base for the 2017-2021 IR Term reflects the above actual in-service amounts for the project to the end of 2015 as well as a forecast of $3.7M in close out capital costs in 2016 (Ex. D2-2-10 Table 2, line 4, col. (k)).

As discussed during the hearing, like other Facilities and Infrastructure Projects, the initial estimates for the Water and Sewer Project were put together prior to engineering completion (Tr. Vol. 3, p. 13). The variances in the project costs were driven by three technical issues encountered while executing the project: (1) change in railway crossing methodology due to existing soil conditions, (2) revised excavation protocol, and (3) revised routing of the sewage and firewater line. Detailed explanations of the project cost variances are outlined in Ex. D2-2-10, Section 2.4.5.2. As the final cost of the project is directly reflective of the work actually required to complete the prerequisite project for the DRP, OPG believes that the full costs for the project were prudently incurred.

UNDERTAKING J20.14

Undertaking

Whether any material Nuclear in-service amounts moved from 2017 to 2018.

Response

OPG's current best-efforts view of Nuclear Operations in-service additions over 2017-2021 (Ex J21.1, Attachment 2, Table 2) shows the 2017 and 2018 Nuclear Operations in-service amounts increasing by approximately $90M and $40M, respectively, when compared to the pre-filed evidence. However, there is no single material in-service amount that is forecast to move between 2017 and 2018.

UNDERTAKING J21.1

Undertaking

To update Table 1 from J14.1 to the forecast OPG requests the OEB to rely on in setting rates and the associated rate base continuities.

Response

OPG does not propose to update its capital in-service forecast for the IR Term from the pre-filed evidence to reflect the impact of actual 2016 capital in-service amounts. Rather, OPG is requesting that the OEB approve nuclear rate base values for 2017-2021 as set out in Ex. A1-2-2, p. 1 (updated on March 8, 2017) and Ex. N2-1-1, p. 5 and detailed at Ex. N2-1-1, Table 1, line 4. These values represent OPG's forecasts in the pre-filed evidence based on OPG's 2016-2018 Business Plan, as updated for two material changes: 1) the removal of the 2017-2021 forecast Heavy Water Storage and Drum Handling Facility ("D2O Project") in service additions (Ex. N2-1-1); and (2) the inclusion of the projected year-end 2016 asset retirement cost adjustment arising from the 2017 ONFA Reference Plan update (Ex N1-1-1). Attachment 1 provides a set of supporting tables, including gross plant and accumulated depreciation and amortization expense continuities, for the proposed net plant rate base inclusive of the above updates. These tables correspond to pre-filed Ex. B3-1-1 Table 1, Ex. B3-3-1 Tables 1 and 2, and Ex. B3-4-1 Tables 1 and 2. No update is required to the pre-filed Nuclear Operations capital in-service table (Ex. D2-1-3 Table 4).

This undertaking follows an exchange with the OPG witnesses at Tr. Vol. 21, p. 3, line 14 to p. 8, line 5 regarding the i pact of the act al 2016 capital in-service amount on the proposed nuclear rate base for the IR Term. As discussed during that exchange and further in Ex. J20.11, potential updating for actual 2016 in-service amounts would also require consideration of changes in the forecast in-service amounts over the full six-year period (2016-2021), including those due to project in-service dates moving across years.

To confirm the reasonableness of maintaining the proposed rate base values without an update in light of the 2016 actual in-service additions, in Attachment 2, OPG provides a current best-efforts view of 2017-2021 Nuclear Operations and Support Services capital in-service amounts (Att. 2, Tables 1 and 2) and corresponding net plant rate base values (Att. 2, Table 3), including the effect of 2016 actuals.[1,2] Attachment 2, Table 2

[1] As ratepayers are held whole with respect to variances in in-service timing and amount for the Darlington Ref rbi sh ent Progra ("DRP") thro gh the Capacity Ref rbish ent Variance Acco nt, Attachment 2 continues to reflect DRP in-service amounts per the pre-filed evidence, adjusted for the removal of the 2017-2021 forecast in-service additions for the D2O Project.

corresponds to Ex. J14.1, Table 1. This view is based on the 2017-2019 Business Plan, adjusted to account for 2016 actuals and subsequent changes in timing of in-service amounts over the 2016-2021 period. The total Nuclear Operations and Support Services in-service amounts in this view are $2,009M over the 2016-2021 period (Att. 2, Table 1), substantially unchanged from the total of $2,008M reflected in the requested rate base (Ex. B1-1-1, Chart 1). On average, the resulting rate base values over the IR Term would be approximately $30M lower than requested, reflecting shifts in in-service timing. On the other hand, annual depreciation expense (excluding asset retirement costs) would be approximately $8M higher than requested, on average, reflecting changes in the anticipated project mix across the nuclear facilities. Attachment 2, Tables 4-7 provide supporting gross plant and accumulated depreciation and amortization continuities for this view.

In OPG's opinion, the current view of capital in-service amounts demonstrates that the requested nuclear rate base remains reasonable.

[2] This view also reflects the actual year-end 2016 asset retirement cost adjustment resulting from the 2017 ONFA Reference Plan update, and associated 2017-2021 annual depreciation expense impacts. The revenue requirement impacts of this adjustment are captured in Ex. J21.2.

Numbers may not add due to rounding.

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Attachment 1
Table 1

Table 1
(Ex. B3-1-1 Table 1 Updated for Ex. N1-1-1 and Ex. N2-1-1)
Prescribed Facility Rate Base - Nuclear ($M)
Years Ending December 31, 2013 to 2021

Line No.	Prescribed Facility	2013 Actual			2014 Actual			2015 Actual		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	801.9	294.8	507.1	870.5	326.9	543.6	939.1	359.6	579.5
2	**Darlington Refurbishment Program**	61.3	1.1	60.2	125.9	4.7	121.2	203.1	10.5	192.6
3	**Pickering NGS**	2,008.1	1,145.8	862.3	2,094.3	1,279.0	815.3	2,170.9	1,422.5	748.4
4	**Nuclear Support Divisions**[1]	332.1	228.1	104.1	354.2	255.6	98.5	369.3	282.6	86.8
5	**Nuclear - Excluding Asset Retirement Costs**	3,203.5	1,669.9	1,533.6	3,444.8	1,866.2	1,578.7	3,682.5	2,075.1	1,607.4
6	**Asset Retirement Costs**	2,839.2	1,369.0	1,470.2	2,839.2	1,449.7	1,389.4	2,839.2	1,530.5	1,308.7
7	**Total**	6,042.7	3,038.9	3,003.8	6,284.0	3,315.9	2,968.1	6,521.7	3,605.6	2,916.1

Line No.	Prescribed Facility	2016 Budget			2017 Plan			2018 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**Darlington NGS**	1,190.5	393.7	796.7	1,461.3	434.2	1,027.1	1,724.6	482.0	1,242.6
9	**Darlington Refurbishment Program**[2]	440.1	21.0	419.1	649.4	37.6	611.9	658.1	56.6	601.5
10	**Pickering NGS**	2,299.1	1,578.6	720.5	2,439.5	1,761.4	678.1	2,525.6	1,972.9	552.7
11	**Nuclear Support Divisions**[1]	389.8	309.2	80.6	411.3	336.0	75.3	427.0	361.3	65.7
12	**Nuclear - Excluding Asset Retirement Costs**	4,319.5	2,302.6	2,016.9	4,961.5	2,569.1	2,392.4	5,335.3	2,872.9	2,462.4
13	**Asset Retirement Costs**[3]	2,421.7	1,596.0	825.7	2,183.7	1,659.8	524.0	2,183.7	1,737.0	446.7
14	**Total**[4]	6,741.2	3,898.5	2,842.6	7,145.2	4,228.9	2,916.4	7,519.1	4,609.9	2,909.2

Line No.	Prescribed Facility	2019 Plan			2020 Plan			2021 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
15	**Darlington NGS**	1,964.6	536.1	1,428.5	2,220.3	595.9	1,624.3	2,438.8	661.8	1,777.0
16	**Darlington Refurbishment Program**[2]	662.5	75.9	586.7	4,858.8	159.8	4,699.1	5,472.0	317.5	5,154.5
17	**Pickering NGS**	2,562.3	2,197.8	364.4	2,569.8	2,427.8	142.0	2,602.3	2,571.0	31.4
18	**Nuclear Support Divisions**[1]	439.1	383.4	55.7	450.8	403.2	47.6	462.7	422.8	40.0
19	**Nuclear - Excluding Asset Retirement Costs**	5,628.5	3,193.3	2,435.3	10,099.7	3,586.7	6,513.0	10,975.9	3,973.1	7,002.9
20	**Asset Retirement Costs**[3]	2,183.7	1,814.3	369.5	2,183.7	1,891.6	292.2	2,183.7	1,934.2	249.6
21	**Total**[4]	7,812.3	5,007.6	2,804.8	12,283.4	5,478.3	6,805.2	13,159.7	5,907.2	7,252.5

Notes:
1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
2 Net plant values for Darlington Refurbishment Program for 2017-2021 are per Ex. N2-1-1, Chart 3.
3 Net plant values for asset retirement costs for 2017-2021 are per Ex. N1-1-1, Attachment 1, Table 3, line 26.
4 Total net plant values for 2017-2021 are per Ex. N2-1-1, Attachment 1, Table 1, line 1.

Numbers may not add due to rounding.

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Attachment 1
Table 2

Table 2
(Ex. B3-3-1 Table 1 Updated for Ex. N1-1-1 and N2-1-1)
Continuity of Gross Property, Plant and Equipment - Nuclear ($M)
Years Ending December 31, 2013 to 2016

Line No.	Prescribed Facility	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2013 Actual[1]:						
1	**Darlington NGS**	759.6	83.4	1.2	84.6	844.2	801.9
2	**Darlington Refurbishment Program[2]**	5.0	99.2	0.0	99.2	104.2	61.3
3	**Pickering NGS**	1,959.6	99.7	(2.6)	97.1	2,056.7	2,008.1
4	**Nuclear Support Divisions[4]**	316.8	33.9	(3.2)	30.7	347.5	332.1
5	**Nuclear - Excluding Asset Retirement Costs**	3,041.0	316.1	(4.6)	311.5	3,352.5	3,203.5
6	**Asset Retirement Costs**	2,839.2	0.0	0.0	0.0	2,839.2	2,839.2
7	**Total**	5,880.2	316.1	(4.6)	311.5	6,191.7	6,042.7
	2014 Actual:						
8	**Darlington NGS**	844.2	52.6	(0.0)	52.5	896.7	870.5
9	**Darlington Refurbishment Program[3]**	104.2	43.5	0.0	43.5	147.6	125.9
10	**Pickering NGS**	2,056.7	75.7	(0.5)	75.2	2,131.9	2,094.3
11	**Nuclear Support Divisions[4]**	347.5	13.4	(0.0)	13.3	360.8	354.2
12	**Nuclear - Excluding Asset Retirement Costs**	3,352.5	185.1	(0.6)	184.6	3,537.1	3,444.8
13	**Asset Retirement Costs**	2,839.2	0.0	0.0	0.0	2,839.2	2,839.2
14	**Total**	6,191.7	185.1	(0.6)	184.6	6,376.3	6,284.0
	2015 Actual:						
15	**Darlington NGS[5]**	896.7	117.4	4.1	121.5	1,018.3	939.1
16	**Darlington Refurbishment Program[6]**	147.6	147.1	0.0	147.1	294.8	203.1
17	**Pickering NGS**	2,131.9	79.6	(1.6)	78.0	2,209.9	2,170.9
18	**Nuclear Support Divisions[4]**	360.8	17.1	(0.1)	17.0	377.9	369.3
19	**Nuclear - Excluding Asset Retirement Costs**	3,537.1	361.2	2.5	363.7	3,900.8	3,682.5
20	**Asset Retirement Costs[7]**	2,839.2	(417.5)	0.0	(417.5)	2,421.7	2,839.2
21	**Total**	6,376.3	(56.3)	2.5	(53.8)	6,322.4	6,521.7
	2016 Budget:						
22	**Darlington NGS[8]**	1,018.3	305.1	0.0	305.1	1,323.4	1,190.5
23	**Darlington Refurbishment Program[9]**	294.8	350.4	0.0	350.4	645.2	440.1
24	**Pickering NGS**	2,209.9	178.4	0.0	178.4	2,388.3	2,299.1
25	**Nuclear Support Divisions[4]**	377.9	24.0	0.0	24.0	401.8	389.8
26	**Nuclear - Excluding Asset Retirement Costs**	3,900.8	857.9	0.0	857.9	4,758.7	4,319.5
27	**Asset Retirement Costs[10]**	2,421.7	0.0	(237.9)	(237.9)	2,183.7	2,421.7
28	**Total**	6,322.4	857.9	(237.9)	620.0	6,942.4	6,741.2

Notes:

1 2013 Actual from EB-2013-0321 Ex. L-1.0-1, Staff-002, Att. 1, Table 2 for the corresponding rows and columns.

2 As shown in EB-2013-0321 Ex. L-9.1-17, SEC-132, Att. 1, Table 12a, Table to Note 1, line 4a.

3 As shown in EB-2014-0370 Ex. H-1-1-2, Table 12a, Table to Note 6, line 1b.

4 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

5 Reflects in-service addition of $55.1M for the Operations Support Building Refurbishment at the end of October 2015. This amount is assigned a two-month weighting in calculating the 2015 Gross Plant Rate Base amount.

6 Reflects in-service addition of $86.6M for the Darlington Refurbishment Program Office in mid September 2015. This amount is assigned a three and a half-month weighting in calculating the 2015 Gross Plant Rate Base amount.

7 The change in asset retirement costs was recorded on December 31, 2015 (from Ex. C2-1-1 Table 2, line 24, col. (c)), therefore the Gross Plant Rate Base amount excludes the impact of this change.

8 Reflects forecast in-service addition of $94.2M for the Auxiliary Heating System in mid April 2016. (Ex. D2-1-3 Table 1, line 11, col. (k)). This amount is assigned an eight and a half-month weighting in calculating the 2016 Gross Plant Rate Base amount.

9 Reflects forecast in-service additions of $87.0M for the R&FR - Tooling for Removal Activities in mid May 2016, $80.1M for the Containment Filtered Venting System in mid August 2016, and $105.3M for the Third Emergency Power Generator in mid October 2016, as shown in Ex. D2-2-10 Table 2, col. (k) at line 2, line 10, and line 9, respectively. These amounts are assigned a seven and a half-month, a four and half-month and a two and a half-month weighting, respectively, in calculating the 2016 Gross Plant Rate Base amount.

10 Reflects the projected decrease in asset retirement costs of $(237.3M) recorded on December 31, 2016 as a result of the 2017 ONFA Reference Plan update (Ex. N1-1-1 Table 3, line 22). The 2016 Gross Plant Rate Base Amount excludes the impact of this change.

Numbers may not add due to rounding.

Table 3
(Ex. B3-3-1 Table 2 Updated for Ex. N1-1-1 and Ex. N2-1-1)
Continuity of Property, Plant and Equipment - Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2017 Plan:						
1	**Darlington NGS**	1,323.4	275.8	0.0	275.8	1,599.2	1,461.3
2	**Darlington Refurbishment Program**	645.2	8.5	0.0	8.5	653.7	649.4
3	**Pickering NGS**	2,388.3	102.4	0.0	102.4	2,490.7	2,439.5
4	**Nuclear Support Divisions[2]**	401.8	18.8	0.0	18.8	420.7	411.3
5	**Nuclear - Excluding Asset Retirement Costs**	4,758.7	405.6	0.0	405.6	5,164.3	4,961.5
6	**Asset Retirement Costs**	2,183.7	0.0	0.0	0.0	2,183.7	2,183.7
7	**Total**	6,942.4	405.6	0.0	405.6	7,348.0	7,145.2
	2018 Plan:						
8	**Darlington NGS**	1,599.2	250.8	0.0	250.8	1,850.0	1,724.6
9	**Darlington Refurbishment Program**	653.7	8.9	0.0	8.9	662.5	658.1
10	**Pickering NGS**	2,490.7	69.7	0.0	69.7	2,560.5	2,525.6
11	**Nuclear Support Divisions[2]**	420.7	12.6	0.0	12.6	433.3	427.0
12	**Nuclear - Excluding Asset Retirement Costs**	5,164.3	342.1	0.0	342.1	5,506.4	5,335.3
13	**Asset Retirement Costs**	2,183.7	0.0	0.0	0.0	2,183.7	2,183.7
14	**Total**	7,348.0	342.1	0.0	342.1	7,690.1	7,519.1
	2019 Plan:						
15	**Darlington NGS**	1,850.0	229.2	0.0	229.2	2,079.2	1,964.6
16	**Darlington Refurbishment Program**	662.5	0.0	0.0	0.0	662.5	662.5
17	**Pickering NGS**	2,560.5	3.6	0.0	3.6	2,564.0	2,562.3
18	**Nuclear Support Divisions[2]**	433.3	11.6	0.0	11.6	444.9	439.1
19	**Nuclear - Excluding Asset Retirement Costs**	5,506.4	244.3	0.0	244.3	5,750.7	5,628.5
20	**Asset Retirement Costs**	2,183.7	0.0	0.0	0.0	2,183.7	2,183.7
21	**Total**	7,690.1	244.3	0.0	244.3	7,934.5	7,812.3
	2020 Plan:						
22	**Darlington NGS**	2,079.2	282.0	0.0	282.0	2,361.3	2,220.3
23	**Darlington Refurbishment Program[3]**	662.5	4,809.2	0.0	4,809.2	5,471.8	4,858.8
24	**Pickering NGS[3]**	2,564.0	11.6	0.0	11.6	2,575.6	2,569.8
25	**Nuclear Support Divisions[2]**	444.9	11.8	0.0	11.8	456.7	450.8
26	**Nuclear - Excluding Asset Retirement Costs**	5,750.7	5,114.7	0.0	5,114.7	10,865.4	10,099.7
27	**Asset Retirement Costs**	2,183.7	0.0	0.0	0.0	2,183.7	2,183.7
28	**Total**	7,934.5	5,114.7	0.0	5,114.7	13,049.1	12,283.4
	2021 Plan:						
29	**Darlington NGS**	2,361.3	155.1	0.0	155.1	2,516.4	2,438.8
30	**Darlington Refurbishment Program**	5,471.8	0.4	0.0	0.4	5,472.2	5,472.0
31	**Pickering NGS[3]**	2,575.6	53.5	0.0	53.5	2,629.1	2,602.3
32	**Nuclear Support Divisions[2]**	456.7	12.0	0.0	12.0	468.7	462.7
33	**Nuclear - Excluding Asset Retirement Costs**	10,865.4	221.1	0.0	221.1	11,086.4	10,975.9
34	**Asset Retirement Costs**	2,183.7	0.0	0.0	0.0	2,183.7	2,183.7
35	**Total**	13,049.1	221.1	0.0	221.1	13,270.2	13,159.7

Notes:

1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

2 Reflects forecast in-service addition of $4,777.7M for the return to service of the refurbished Darlington Unit 2 in mid February 2020 (included in amount at Ex. D2-2-10 Table 2, line 1, col. (o)). This amount is assigned a ten and a half-month weighting in calculating the 2020 Gross Plant Rate Base amount.

3 The closing net plant balance for Pickering NGS in 2020 and 2021 reflects minor fixed assets (e.g., portable equipment) assumed to be transferrable to support other parts of OPG's regulated operations.

Numbers may not add due to rounding.

Table 4
(Ex. B3-4-1 Table 1)
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)
Years Ending December 31, 2013 to 2016

Line No.	Prescribed Facility	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	2013 Actual[1]:					
1	**Darlington NGS**	279.8	32.3	(2.2)	309.9	294.8
2	**Darlington Refurbishment Program[2]**	0.0	2.3	0.0	2.3	1.1
3	**Pickering NGS**	1,082.9	127.5	(1.7)	1,208.7	1,145.8
4	**Nuclear Support Divisions[3]**	214.2	27.3	0.4	241.9	228.1
5	**Nuclear - Excluding Asset Retirement Costs**	1,576.9	189.4	(3.5)	1,762.8	1,669.9
6	**Asset Retirement Costs**	1,328.6	80.7	0.0	1,409.4	1,369.0
7	**Total**	2,905.6	270.1	(3.5)	3,172.2	3,038.9
	2014 Actual:					
8	**Darlington NGS**	309.9	34.0	(0.0)	343.8	326.9
9	**Darlington Refurbishment Program[4]**	2.3	4.7	0.0	7.0	4.7
10	**Pickering NGS**	1,208.7	140.9	(0.5)	1,349.2	1,279.0
11	**Nuclear Support Divisions[3]**	241.9	27.4	(0.0)	269.3	255.6
12	**Nuclear - Excluding Asset Retirement Costs**	1,762.8	207.0	(0.5)	1,969.3	1,866.2
13	**Asset Retirement Costs**	1,409.4	80.7	0.0	1,490.1	1,449.7
14	**Total**	3,172.2	287.8	(0.5)	3,459.4	3,315.9
	2015 Actual:					
15	**Darlington NGS**	343.8	31.5	(0.0)	375.4	359.6
16	**Darlington Refurbishment Program**	7.0	7.0	0.0	14.0	10.5
17	**Pickering NGS**	1,349.2	147.3	(0.8)	1,495.8	1,422.5
18	**Nuclear Support Divisions[3]**	269.3	26.6	(0.1)	295.8	282.6
19	**Nuclear - Excluding Asset Retirement Costs**	1,969.3	212.4	(0.9)	2,180.9	2,075.1
20	**Asset Retirement Costs**	1,490.1	80.7	0.0	1,570.8	1,530.5
21	**Total**	3,459.4	293.2	(0.9)	3,751.7	3,605.6

Notes:
1 2013 Actual from EB-2013-0321 Ex. L-1.0-1, Staff-002, Att. 1, Table 3.
2 As shown in EB-2013-0321 Ex. L-9.1-17, SEC-132, Att. 1, Table 12a, Table to Note 1, line 5a.
3 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
4 As shown in EB-2014-0370 Ex. H1-1-2, Table 12a, Table to Note 6, line 2b.

Numbers may not add due to rounding.

Table 5
(Ex. B3-4-1 Table 2 Updated for Ex. N1-1-1 and Ex. N2-1-1)
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Opening Balance	Depreciation and Amortization on Opening Balance	Depreciation and Amortization on In-Service Additions	Retirements, Transfers & Adjustments	(a)+(b)+(c)+(d) Closing Balance	(a+e)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2016 Budget:						
1	**Darlington NGS**	375.4	31.8	4.9	0.0	412.1	393.7
2	**Darlington Refurbishment Program**	14.0	9.6	4.5	0.0	28.1	21.0
3	**Pickering NGS**	1,495.8	146.4	19.3	0.0	1,661.4	1,578.6
4	**Nuclear Support Divisions**[1]	295.8	23.8	3.0	0.0	322.6	309.2
5	**Nuclear - Excluding Asset Retirement Costs**	2,180.9	211.7	31.7	0.0	2,424.2	2,302.6
6	**Asset Retirement Costs**	1,570.8	50.3	0.0	0.0	1,621.1	1,596.0
7	**Total**	3,751.7	261.9	31.7	0.0	4,045.4	3,898.5
	2017 Plan:						
8	**Darlington NGS**	412.1	39.9	4.3	0.0	456.4	434.2
9	**Darlington Refurbishment Program**	28.1	12.4	6.5	0.0	47.0	37.6
10	**Pickering NGS**	1,661.4	185.3	14.6	0.0	1,861.3	1,761.4
11	**Nuclear Support Divisions**[1]	322.6	24.3	2.4	0.0	349.3	336.0
12	**Nuclear - Excluding Asset Retirement Costs**	2,424.2	262.0	27.8	0.0	2,714.0	2,569.1
13	**Asset Retirement Costs**	1,621.1	77.3	0.0	0.0	1,698.4	1,659.8
14	**Total**	4,045.4	339.2	27.8	0.0	4,412.4	4,228.9
	2018 Plan:						
15	**Darlington NGS**	456.4	47.3	4.1	0.0	507.7	482.0
16	**Darlington Refurbishment Program**	47.0	19.1	0.1	0.0	66.2	56.6
17	**Pickering NGS**	1,861.3	209.5	13.7	0.0	2,084.5	1,972.9
18	**Nuclear Support Divisions**[1]	349.3	22.5	1.6	0.0	373.4	361.3
19	**Nuclear - Excluding Asset Retirement Costs**	2,714.0	298.3	19.5	0.0	3,031.8	2,872.9
20	**Asset Retirement Costs**	1,698.4	77.3	0.0	0.0	1,775.7	1,737.0
21	**Total**	4,412.4	375.6	19.5	0.0	4,807.4	4,609.9
	2019 Plan:						
22	**Darlington NGS**	507.7	53.0	3.9	0.0	564.6	536.1
23	**Darlington Refurbishment Program**	66.2	19.3	0.0	0.0	85.6	75.9
24	**Pickering NGS**	2,084.5	226.2	0.4	0.0	2,311.2	2,197.8
25	**Nuclear Support Divisions**[1]	373.4	18.7	1.4	0.0	393.5	383.4
26	**Nuclear - Excluding Asset Retirement Costs**	3,031.8	317.3	5.7	0.0	3,354.8	3,193.3
27	**Asset Retirement Costs**	1,775.7	77.3	0.0	0.0	1,852.9	1,814.3
28	**Total**	4,807.4	394.5	5.7	0.0	5,207.7	5,007.6
	2020 Plan:						
29	**Darlington NGS**	564.6	58.6	4.1	0.0	627.3	595.9
30	**Darlington Refurbishment Program**	85.6	19.3	129.1	0.0	234.0	159.8
31	**Pickering NGS**	2,311.2	224.8	8.5	0.0	2,544.4	2,427.8
32	**Nuclear Support Divisions**[1]	393.5	17.3	2.2	0.0	413.0	403.2
33	**Nuclear - Excluding Asset Retirement Costs**	3,354.8	320.0	143.9	0.0	3,818.7	3,586.7
34	**Asset Retirement Costs**	1,852.9	77.3	0.0	0.0	1,930.2	1,891.6
35	**Total**	5,207.7	397.3	143.9	0.0	5,748.9	5,478.3
	2021 Plan:						
36	**Darlington NGS**	627.3	66.2	2.9	0.0	696.4	661.8
37	**Darlington Refurbishment Program**	234.0	166.9	0.0	0.0	400.9	317.5
38	**Pickering NGS**[2]	2,544.4	2.3	50.8	0.0	2,597.5	2,571.0
39	**Nuclear Support Divisions**[1]	413.0	18.1	1.5	0.0	432.5	422.8
40	**Nuclear - Excluding Asset Retirement Costs**	3,818.7	253.5	55.3	0.0	4,127.4	3,973.1
41	**Asset Retirement Costs**	1,930.2	7.9	0.0	0.0	1,938.1	1,934.2
42	**Total**	5,748.9	261.4	55.3	0.0	6,065.6	5,907.2

Notes:
1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
2 Pickering in-service additions (other than for minor fixed assets assumed to be transferrable to other parts of OPG's regulated operations) in 2021 are shown as fully depreciated in 2021, in line with the current December 31, 2020 end-of-life date for the stations, as discussed in Ex. F4-1-1 section 3.2.

Table 1
Forecast Nuclear In-Service Capital Additions
(Current View of Ex. B1-1-1 Chart 1)

	Actual 2016	2017	2018	2019	2020	2021
Nuclear Operations capital projects[1]	292.0	479.0	354.7	385.4	244.7	181.6
Darlington Refurbishment Program[2]	350.4	8.5	8.9	0.0	4,809.2	0.4
Support Services capital projects entering rate base	8.9	29.8	17.4	7.7	4.7	3.2
Total nuclear in-service additions, excluding ARC	**651.3**	**517.3**	**381.0**	**393.0**	**5,058.6**	**185.2**

[1] Actual 2016 as shown in Ex. J14.1, Att. 1, Table 1, col. (e), line 17.

[2] As discussed in Ex. J21.1, footnote 1, for DRP, pre-filed in-service amounts are reflected for all years, excluding the D2O Project.

Numbers may not add due to rounding.

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J21.1
Attachment 2
Table 2

Table 2
(Current View of Ex. J14.1, Table 1)
Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	89.9	(10.0)	79.9	(48.8)	43.8	(12.8)	31.1	75.9	7.7	99.3	107.0
2	**Pickering NGS**	53.6	41.3	94.9	(26.2)	48.8	19.9	68.7	3.0	12.5	59.1	71.7
3	**Nuclear Support Divisions**[1]	17.4	10.2	27.6	(1.6)	6.4	19.6	26.0	(22.9)	0.7	2.4	3.1
4	**Subtotal**	160.8	41.6	202.4	(76.7)	99.1	26.7	125.7	56.0	20.9	160.9	181.8
5	**Supplemental In-Service Forecast**[2]	0.0	0.0	0.0	0.0	37.9	(37.9)	0.0	0.0	99.1	(99.1)	0.0
6	**Total Portfolio In-Service Forecast**	160.8	41.6	202.4	(76.7)	137.0	(11.3)	125.7	56.0	120.0	61.7	181.8
7	**Minor Fixed Assets**	19.9	(9.7)	10.2	12.6	21.3	1.6	22.9	(0.5)	21.7	0.6	22.3
8	**Total In-Service Capital Additions**	180.7	31.9	212.6	(64.0)	158.3	(9.7)	148.6	55.5	141.7	62.4	204.1

Line No.	Business Unit	2015 Actual	(e)-(a) Change	2016 Budget	(e)-(c) Change	2016 Actual	(g)-(e) Change	2017 Plan	(i)-(g) Change	2018 Plan	(k)-(i) Change	2019 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Darlington NGS**	107.0	112.8	331.4	(111.6)	219.8	13.8	233.6	(15.2)	218.4	121.6	340.0
10	**Pickering NGS**	71.7	(23.8)	164.9	(117.0)	47.9	149.8	197.7	(147.2)	50.5	(40.8)	9.7
11	**Nuclear Support Divisions**[1]	3.1	(1.3)	17.1	(15.3)	1.8	19.8	21.6	19.3	40.9	(40.9)	0.0
12	**Subtotal**	181.8	87.7	513.4	(243.9)	269.5	183.5	453.0	(143.2)	309.8	40.0	349.8
13	**Supplemental In-Service Forecast**[2]	0.0	0.0	(47.4)	47.4	0.0	0.0	0.0	0.0	24.9	0.0	16.6
14	**Total Portfolio In-Service Forecast**	181.8	87.7	466.0	(196.5)	269.5	183.5	453.0	(143.2)	334.7	40.0	366.3
15	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	**Minor Fixed Assets**	22.3	0.2	31.0	(8.5)	22.5	3.5	26.0	(6.0)	20.0	(0.9)	19.1
17	**Total In-Service Capital Additions**	204.1	87.9	497.0	(205.0)	292.0	187.0	479.0	(149.2)	354.7	39.1	385.4

Line No.	Business Unit	2019 Plan	(c)-(a) Change	2020 Plan	(e)-(c) Change	2021 Plan
		(a)	(b)	(c)	(d)	(e)
18	**Darlington NGS**	340.0	(209.0)	131.0	(68.9)	62.1
19	**Pickering NGS**	9.7	(9.7)	0.0	0.0	0.0
20	**Nuclear Support Divisions**[1]	0.0	0.0	0.0	0.0	0.0
21	**Subtotal**	349.8	(218.8)	131.0	(68.9)	62.1
22	**Supplemental In-Service Forecast**[2]	16.6	62.3	78.8	21.4	100.2
23	**Total Portfolio In-Service Forecast**	366.3	(156.5)	209.8	(47.5)	162.3
24	**Darlington New Fuel**	0.0	15.3	15.3	(15.3)	0.0
25	**Minor Fixed Assets**	19.1	0.4	19.5	(0.1)	19.3
26	**Total In-Service Capital Additions**	385.4	(140.7)	244.7	(63.0)	181.6

Notes:
1 Includes Engineering, Inspection and Maintenance Services, and Security & Emergency Services.
2 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

Numbers may not add due to rounding.

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J21.1
Attachment 2
Table 3

Table 3
(Current View of Ex. B3-1-1 Table 1)
Prescribed Facility Rate Base - Nuclear ($M)
Years Ending December 31, 2013 to 2021

Line No.	Prescribed Facility	2013 Actual			2014 Actual			2015 Actual		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	801.9	294.8	507.1	870.5	326.9	543.6	939.1	359.6	579.5
2	**Darlington Refurbishment Program**	61.3	1.1	60.2	125.9	4.7	121.2	203.1	10.5	192.6
3	**Pickering NGS**	2,008.1	1,145.8	862.3	2,094.3	1,279.0	815.3	2,170.9	1,422.5	748.4
4	**Nuclear Support Divisions[1]**	332.1	228.1	104.1	354.2	255.6	98.5	369.3	282.6	86.8
5	**Nuclear - Excluding Asset Retirement Costs**	3,203.5	1,669.9	1,533.6	3,444.8	1,866.2	1,578.7	3,682.5	2,075.1	1,607.4
6	**Asset Retirement Costs[2]**	2,839.2	1,369.0	1,470.2	2,839.2	1,449.7	1,389.4	2,839.2	1,530.5	1,308.7
7	**Total**	6,042.7	3,038.9	3,003.8	6,284.0	3,315.9	2,968.1	6,521.7	3,605.6	2,916.1

Line No.	Prescribed Facility	2016 Actual			2017 Plan			2018 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**Darlington NGS**	1,152.4	394.9	757.5	1,385.3	436.6	948.7	1,656.5	484.7	1,171.9
9	**Darlington Refurbishment Program[3]**	440.1	21.0	419.1	649.4	37.6	611.9	658.1	56.6	601.5
10	**Pickering NGS**	2,235.2	1,570.7	664.5	2,367.0	1,736.7	630.3	2,522.5	1,941.6	581.0
11	**Nuclear Support Divisions[1]**	384.0	307.2	76.7	398.5	331.4	67.1	412.2	355.5	56.7
12	**Nuclear - Excluding Asset Retirement Costs**	4,211.7	2,293.9	1,917.9	4,800.2	2,542.3	2,258.0	5,249.4	2,838.3	2,411.1
13	**Asset Retirement Costs[2]**	2,421.7	1,596.0	825.7	2,163.3	1,658.2	505.1	2,163.3	1,732.3	431.0
14	**Total**	6,633.4	3,889.8	2,743.5	6,963.5	4,200.4	2,763.1	7,412.7	4,570.6	2,842.1

Line No.	Prescribed Facility	2019 Plan			2020 Plan			2021 Plan		
		Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant	Gross Plant at Cost	Less: Accumulated Depreciation and Amortization	Net Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
15	**Darlington NGS**	1,964.0	540.2	1,423.8	2,240.7	603.2	1,637.5	2,413.2	672.2	1,741.1
16	**Darlington Refurbishment Program[3]**	662.5	75.9	586.7	4,858.8	159.8	4,699.1	5,472.0	317.5	5,154.5
17	**Pickering NGS**	2,587.6	2,178.5	409.1	2,622.7	2,445.5	177.2	2,657.5	2,605.1	52.5
18	**Nuclear Support Divisions[1]**	422.2	376.3	45.9	431.7	395.2	36.5	441.4	412.9	28.5
19	**Nuclear - Excluding Asset Retirement Costs**	5,636.4	3,171.0	2,465.5	10,153.9	3,603.7	6,550.2	10,984.2	4,007.6	6,976.6
20	**Asset Retirement Costs[2]**	2,163.3	1,806.5	356.8	2,163.3	1,880.6	282.7	2,163.3	1,921.5	241.8
21	**Total**	7,799.7	4,977.4	2,822.3	12,317.2	5,484.3	6,832.9	13,147.5	5,929.1	7,218.4

Notes:
1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
2 Starting in 2017, updated to reflect the decrease in asset retirement costs of $(258.3M) recorded on December 31, 2016 as a result of the 2017 ONFA Reference Plan update, and associated annual depreciation expense impacts.
3 As discussed in Ex. J21.1, footnote 1, for DRP, pre-filed in-service amounts are reflected for all years, excluding D2O Project.

Numbers may not add due to rounding.

Table 4
(Current View of Ex. B3-3-1 Table 1)
Continuity of Gross Property, Plant and Equipment - Nuclear ($M)
Years Ending December 31, 2013 to 2016

Line No.	Prescribed Facility	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2013 Actual[1]:						
1	**Darlington NGS**	759.6	83.4	1.2	84.6	844.2	801.9
2	**Darlington Refurbishment Program[2]**	5.0	99.2	0.0	99.2	104.2	61.3
3	**Pickering NGS**	1,959.6	99.7	(2.6)	97.1	2,056.7	2,008.1
4	**Nuclear Support Divisions[4]**	316.8	33.9	(3.2)	30.7	347.5	332.1
5	**Nuclear - Excluding Asset Retirement Costs**	3,041.0	316.1	(4.6)	311.5	3,352.5	3,203.5
6	**Asset Retirement Costs**	2,839.2	0.0	0.0	0.0	2,839.2	2,839.2
7	**Total**	5,880.2	316.1	(4.6)	311.5	6,191.7	6,042.7
	2014 Actual:						
8	**Darlington NGS**	844.2	52.6	(0.0)	52.5	896.7	870.5
9	**Darlington Refurbishment Program[3]**	104.2	43.5	0.0	43.5	147.6	125.9
10	**Pickering NGS**	2,056.7	75.7	(0.5)	75.2	2,131.9	2,094.3
11	**Nuclear Support Divisions[4]**	347.5	13.4	(0.0)	13.3	360.8	354.2
12	**Nuclear - Excluding Asset Retirement Costs**	3,352.5	185.1	(0.6)	184.6	3,537.1	3,444.8
13	**Asset Retirement Costs**	2,839.2	0.0	0.0	0.0	2,839.2	2,839.2
14	**Total**	6,191.7	185.1	(0.6)	184.6	6,376.3	6,284.0
	2015 Actual:						
15	**Darlington NGS[5]**	896.7	117.4	4.1	121.5	1,018.3	939.1
16	**Darlington Refurbishment Program[6]**	147.6	147.1	0.0	147.1	294.8	203.1
17	**Pickering NGS**	2,131.9	79.6	(1.6)	78.0	2,209.9	2,170.9
18	**Nuclear Support Divisions[4]**	360.8	17.1	(0.1)	17.0	377.9	369.3
19	**Nuclear - Excluding Asset Retirement Costs**	3,537.1	361.2	2.5	363.7	3,900.8	3,682.5
20	**Asset Retirement Costs[7]**	2,839.2	(417.5)	0.0	(417.5)	2,421.7	2,839.2
21	**Total**	6,376.3	(56.3)	2.5	(53.8)	6,322.4	6,521.7
	2016 Actual:[11]						
22	**Darlington NGS[8]**	1,018.3	228.1	(0.7)	227.5	1,245.8	1,152.4
23	**Darlington Refurbishment Program[9,10]**	294.8	350.4	0.0	350.4	645.2	440.1
24	**Pickering NGS**	2,209.9	51.3	(0.6)	50.7	2,260.6	2,235.2
25	**Nuclear Support Divisions[4]**	377.9	15.8	(3.6)	12.2	390.1	384.0
26	**Nuclear - Excluding Asset Retirement Costs**	3,900.8	645.7	(4.9)	640.8	4,541.6	4,148.6
27	**Asset Retirement Costs[12]**	2,421.7	(258.3)	0.0	(258.3)	2,163.3	2,421.7
28	**Total**	6,322.4	387.3	(4.9)	382.4	6,704.9	6,570.2

Notes:

1 2013 Actual from EB-2013-0321 Ex. L-1.0-1, Staff-002, Att. 1, Table 2 for the corresponding rows and columns.
2 As shown in EB-2013-0321 Ex. L-9.1-17, SEC-132, Att. 1, Table 12a, Table to Note 1, line 4a.
3 As shown in EB-2014-0370 Ex. H-1-1-2, Table 12a, Table to Note 6, line 1b.
4 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
5 Reflects in-service addition of $55.1M for the Operations Support Building Refurbishment at the end of October 2015. This amount is assigned a two-month weighting in calculating the 2015 Gross Plant Rate Base amount.
6 Reflects in-service addition of $86.6M for the Darlington Refurbishment Program Office in mid September 2015. This amount is assigned a three and a half-month weighting in calculating the 2015 Gross Plant Rate Base amount.
7 The change in asset retirement costs was recorded on December 31, 2015 (from Ex. C2-1-1 Table 2, line 24, col. (c)), therefore the Gross Plant Rate Base amount excludes the impact of this change.
8 Reflects an in-service addition of $68.8M for the Auxiliary Heating System in mid March 2016. This amount is assigned an nine and a half-month weighting in calculating the 2016 Gross Plant Rate Base amount.
9 As discussed in Ex. J21.1, footnote 1, for DRP, pre-filed in-service amounts are reflected for 2016 onwards, excluding D2O Project.
10 Reflects forecast in-service additions of $87.0M for the R&FR - Tooling for Removal Activities in mid May 2016, $80.1M for the Containment Filtered Venting System in mid August 2016, and $105.3M for the Third Emergency Power Generator in mid October 2016, as shown in Ex. D2-2-10 Table 2, col. (k) at line 2, line 10, and line 9, respectively. These amounts are assigned a seven and a half-month, a four and half-month and a two and a half-month weighting, respectively, in calculating the 2016 Gross Plant Rate Base amount.
11 The difference between the sum of 2016 in-service additions in col. (b), lines 22, 24 and 25 and the sum of 2016 Nuclear Operations and Support Services in-service additions at Ex. J20.10, Attachment 1, Table 1 relates to self-correcting inter-period timing differences of the type described in Ex. L-2.1-1 Staff-007.
12 Reflects the decrease in asset retirement costs of $(258.3M) recorded on December 31, 2016 as a result of the 2017 ONFA Reference Plan update.

Numbers may not add due to rounding.

Table 5
(Current View of Ex. B3-3-1 Table 2)
Continuity of Property, Plant and Equipment - Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Gross Plant Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	(b)+(c) Net Change	(a)+(d) Closing Balance	(a+e)/2 Gross Plant Rate Base Amount
		(a)	(b)	(c)	(d)	(e)	(f)
	2017 Plan:						
1	**Darlington NGS**	1,245.8	279.2	0.0	279.2	1,524.9	1,385.3
2	**Darlington Refurbishment Program[1]**	645.2	8.5	0.0	8.5	653.7	649.4
3	**Pickering NGS**	2,260.6	212.8	0.0	212.8	2,473.4	2,367.0
4	**Nuclear Support Divisions[2]**	390.1	16.8	0.0	16.8	406.9	398.5
5	**Nuclear - Excluding Asset Retirement Costs**	4,541.6	517.3	0.0	517.3	5,058.9	4,800.2
6	**Asset Retirement Costs[5]**	2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
7	**Total**	6,704.9	517.3	0.0	517.3	7,222.2	6,963.5
	2018 Plan:						
8	**Darlington NGS**	1,524.9	263.2	0.0	263.2	1,788.2	1,656.5
9	**Darlington Refurbishment Program[1]**	653.7	8.9	0.0	8.9	662.5	658.1
10	**Pickering NGS**	2,473.4	98.4	0.0	98.4	2,571.7	2,522.5
11	**Nuclear Support Divisions[2]**	406.9	10.5	0.0	10.5	417.5	412.2
12	**Nuclear - Excluding Asset Retirement Costs**	5,058.9	381.0	0.0	381.0	5,439.9	5,249.4
13	**Asset Retirement Costs[5]**	2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
14	**Total**	7,222.2	381.0	0.0	381.0	7,603.2	7,412.7
	2019 Plan:						
15	**Darlington NGS**	1,788.2	351.8	0.0	351.8	2,139.9	1,964.0
16	**Darlington Refurbishment Program[1]**	662.5	0.0	0.0	0.0	662.5	662.5
17	**Pickering NGS**	2,571.7	31.8	0.0	31.8	2,603.5	2,587.6
18	**Nuclear Support Divisions[2]**	417.5	9.5	0.0	9.5	426.9	422.2
19	**Nuclear - Excluding Asset Retirement Costs**	5,439.9	393.0	0.0	393.0	5,832.9	5,636.4
20	**Asset Retirement Costs[5]**	2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
21	**Total**	7,603.2	393.0	0.0	393.0	7,996.3	7,799.7
	2020 Plan:						
22	**Darlington NGS**	2,139.9	201.5	0.0	201.5	2,341.4	2,240.7
23	**Darlington Refurbishment Program[1, 3]**	662.5	4,809.2	0.0	4,809.2	5,471.8	4,858.8
24	**Pickering NGS[4]**	2,603.5	38.3	0.0	38.3	2,641.8	2,622.7
25	**Nuclear Support Divisions[2]**	426.9	9.6	0.0	9.6	436.5	431.7
26	**Nuclear - Excluding Asset Retirement Costs**	5,832.9	5,058.6	0.0	5,058.6	10,891.6	10,153.9
27	**Asset Retirement Costs[5]**	2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
28	**Total**	7,996.3	5,058.6	0.0	5,058.6	13,054.9	12,317.2
	2021 Plan:						
29	**Darlington NGS**	2,341.4	143.7	0.0	143.7	2,485.1	2,413.2
30	**Darlington Refurbishment Program[1]**	5,471.8	0.4	0.0	0.4	5,472.2	5,472.0
31	**Pickering NGS[4]**	2,641.8	31.4	0.0	31.4	2,673.2	2,657.5
32	**Nuclear Support Divisions[2]**	436.5	9.7	0.0	9.7	446.3	441.4
33	**Nuclear - Excluding Asset Retirement Costs**	10,891.6	185.2	0.0	185.2	11,076.8	10,984.2
34	**Asset Retirement Costs[5]**	2,163.3	0.0	0.0	0.0	2,163.3	2,163.3
35	**Total**	13,054.9	185.2	0.0	185.2	13,240.1	13,147.5

Notes:

1 As discussed in Ex. J21.1, footnote 1, for DRP, pre-filed in-service amounts are reflected for 2016 onwards, excluding D2O Project.

2 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

3 Reflects forecast in-service addition of $4,777.7M for the return to service of the refurbished Darlington Unit 2 in mid February 2020 (included in amount at Ex. D2-2-10 Table 2, line 1, col. (o)). This amount is assigned a ten and a half-month weighting in calculating the 2020 Gross Plant Rate Base amount.

4 The closing net plant balance for Pickering NGS in 2020 and 2021 reflects minor fixed assets (e.g., portable equipment) assumed to be transferrable to support other parts of OPG's regulated operations.

Numbers may not add due to rounding.

Table 6
(Ex. B3-4-1 Table 1)
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)
Years Ending December 31, 2013 to 2016

Line No.	Prescribed Facility	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	2013 Actual[1]:					
1	**Darlington NGS**	279.8	32.3	(2.2)	309.9	294.8
2	**Darlington Refurbishment Program[2]**	0.0	2.3	0.0	2.3	1.1
3	**Pickering NGS**	1,082.9	127.5	(1.7)	1,208.7	1,145.8
4	**Nuclear Support Divisions[3]**	214.2	27.3	0.4	241.9	228.1
5	**Nuclear - Excluding Asset Retirement Costs**	1,576.9	189.4	(3.5)	1,762.8	1,669.9
6	**Asset Retirement Costs**	1,328.6	80.7	0.0	1,409.4	1,369.0
7	**Total**	2,905.6	270.1	(3.5)	3,172.2	3,038.9
	2014 Actual:					
8	**Darlington NGS**	309.9	34.0	(0.0)	343.8	326.9
9	**Darlington Refurbishment Program[4]**	2.3	4.7	0.0	7.0	4.7
10	**Pickering NGS**	1,208.7	140.9	(0.5)	1,349.2	1,279.0
11	**Nuclear Support Divisions[3]**	241.9	27.4	(0.0)	269.3	255.6
12	**Nuclear - Excluding Asset Retirement Costs**	1,762.8	207.0	(0.5)	1,969.3	1,866.2
13	**Asset Retirement Costs**	1,409.4	80.7	0.0	1,490.1	1,449.7
14	**Total**	3,172.2	287.8	(0.5)	3,459.4	3,315.9
	2015 Actual:					
15	**Darlington NGS**	343.8	31.5	(0.0)	375.4	359.6
16	**Darlington Refurbishment Program**	7.0	7.0	0.0	14.0	10.5
17	**Pickering NGS**	1,349.2	147.3	(0.8)	1,495.8	1,422.5
18	**Nuclear Support Divisions[3]**	269.3	26.6	(0.1)	295.8	282.6
19	**Nuclear - Excluding Asset Retirement Costs**	1,969.3	212.4	(0.9)	2,180.9	2,075.1
20	**Asset Retirement Costs**	1,490.1	80.7	0.0	1,570.8	1,530.5
21	**Total**	3,459.4	293.2	(0.9)	3,751.7	3,605.6

Notes:

1 2013 Actual from EB-2013-0321 Ex. L-1.0-1, Staff-002, Att. 1, Table 3.

2 As shown in EB-2013-0321 Ex. L-9.1-17, SEC-132, Att. 1, Table 12a, Table to Note 1, line 5a.

3 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).

4 As shown in EB-2014-0370 Ex. H1-1-2, Table 12a, Table to Note 6, line 2b.

Numbers may not add due to rounding.

Table 7
(Current View of Ex. B3-4-1 Table 2)
Continuity of Accumulated Depreciation and Amortization - Nuclear ($M)
Years Ending December 31, 2017 to 2021

Line No.	Prescribed Facility	Opening Balance	Depreciation and Amortization[4]	Retirements, Transfers & Adjustments	(a)+(b)+(c) Closing Balance	(a+d)/2 Accumulated Depreciation and Amortization Rate Base Amount
		(a)	(b)	(c)	(d)	(e)
	2016 Actual:					
1	**Darlington NGS**	375.4	39.3	(0.2)	414.5	394.9
2	**Darlington Refurbishment Program[3]**	14.0	14.1	0.0	28.1	21.0
3	**Pickering NGS**	1,495.8	150.4	(0.5)	1,645.6	1,570.7
4	**Nuclear Support Divisions[1]**	295.8	24.6	(1.8)	318.6	307.2
5	**Nuclear - Excluding Asset Retirement Costs**	2,180.9	228.4	(2.5)	2,406.8	2,293.9
6	**Asset Retirement Costs**	1,570.8	50.3	0.0	1,621.1	1,596.0
7	**Total**	3,751.7	278.7	(2.5)	4,028.0	3,889.8
	2017 Plan:					
8	**Darlington NGS**	414.5	44.2	0.0	458.7	436.6
9	**Darlington Refurbishment Program[3]**	28.1	18.9	0.0	47.0	37.6
10	**Pickering NGS**	1,645.6	182.0	0.0	1,827.7	1,736.7
11	**Nuclear Support Divisions[1]**	318.6	25.6	0.0	344.2	331.4
12	**Nuclear - Excluding Asset Retirement Costs**	2,406.8	270.8	0.0	2,677.7	2,542.3
13	**Asset Retirement Costs[5]**	1,621.1	74.1	0.0	1,695.3	1,658.2
14	**Total**	4,028.0	345.0	0.0	4,372.9	4,200.4
	2018 Plan:					
15	**Darlington NGS**	458.7	51.9	0.0	510.6	484.7
16	**Darlington Refurbishment Program[3]**	47.0	19.2	0.0	66.2	56.6
17	**Pickering NGS**	1,827.7	227.7	0.0	2,055.4	1,941.6
18	**Nuclear Support Divisions[1]**	344.2	22.5	0.0	366.7	355.5
19	**Nuclear - Excluding Asset Retirement Costs**	2,677.7	321.3	0.0	2,998.9	2,838.3
20	**Asset Retirement Costs[5]**	1,695.3	74.1	0.0	1,769.4	1,732.3
21	**Total**	4,372.9	395.4	0.0	4,768.3	4,570.6
	2019 Plan:					
22	**Darlington NGS**	510.6	59.3	0.0	569.9	540.2
23	**Darlington Refurbishment Program[3]**	66.2	19.3	0.0	85.6	75.9
24	**Pickering NGS**	2,055.4	246.2	0.0	2,301.6	2,178.5
25	**Nuclear Support Divisions[1]**	366.7	19.3	0.0	385.9	376.3
26	**Nuclear - Excluding Asset Retirement Costs**	2,998.9	344.0	0.0	3,343.0	3,171.0
27	**Asset Retirement Costs[5]**	1,769.4	74.1	0.0	1,843.5	1,806.5
28	**Total**	4,768.3	418.2	0.0	5,186.5	4,977.4
	2020 Plan:					
29	**Darlington NGS**	569.9	66.7	0.0	636.6	603.2
30	**Darlington Refurbishment Program[3]**	85.6	148.4	0.0	234.0	159.8
31	**Pickering NGS**	2,301.6	287.7	0.0	2,589.3	2,445.5
32	**Nuclear Support Divisions[1]**	385.9	18.5	0.0	404.5	395.2
33	**Nuclear - Excluding Asset Retirement Costs**	3,343.0	521.3	0.0	3,864.3	3,603.7
34	**Asset Retirement Costs[5]**	1,843.5	74.1	0.0	1,917.7	1,880.6
35	**Total**	5,186.5	595.5	0.0	5,782.0	5,484.3
	2021 Plan:					
36	**Darlington NGS**	636.6	71.3	0.0	707.8	672.2
37	**Darlington Refurbishment Program[3]**	234.0	166.9	0.0	400.9	317.5
38	**Pickering NGS[2]**	2,589.3	31.5	0.0	2,620.8	2,605.1
39	**Nuclear Support Divisions[1]**	404.5	16.8	0.0	421.3	412.9
40	**Nuclear - Excluding Asset Retirement Costs**	3,864.4	286.5	0.0	4,150.9	4,007.6
41	**Asset Retirement Costs[5]**	1,917.7	7.7	0.0	1,925.4	1,921.5
42	**Total**	5,782.0	294.2	0.0	6,076.2	5,929.1

Notes:
1 Includes support divisions within nuclear accountable for providing specialized services (e.g. Nuclear Engineering, Inspection and Maintenance Services).
2 Pickering in-service additions (other than for minor fixed assets assumed to be transferrable to other parts of OPG's regulated operations) in 2021 are shown as fully depreciated in 2021, in line with the current December 31, 2020 end-of-life date for the stations, as discussed in Ex. F4-1-1 section 3.2.
3 As discussed in Ex. J21.1, footnote 1, for DRP, pre-filed in-service amounts are reflected for 2016 onwards, excluding D2O Project.
4 On a best efforts basis, OPG has provided the depreciation forecast for opening gross plant and in-service additions on a combined basis.
5 Reflects the impact of the decrease in asset retirement costs of $(258.3M) recorded on December 31, 2016 as a result of the 2017 ONFA Reference Plan update.

UNDERTAKING J21.2

Undertaking

To updated Ex. C2-1-2, Chart 1, with best available information.

Response

Ex. C2-1-2, Chart 1 below has been updated with the impacts of the 2017 ONFA Contribution Schedule approved by the Province on February 28, 2017, the actual year-end 2016 asset retirement obligation ("ARO") adjustment reflected in the company's audited consolidated financial statements issued on March 10, 2017, and the year-end 2016 discount rate that will be used to determine used fuel and low and intermediate level waste variable expenses until the next ARO adjustment.

Chart 1
Updated Summary of Revenue Requirement Impact of Nuclear Liabilities ($M)

Line No.	Description	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
	Prescribed Facilities							
1	Pre-Tax Revenue Requirement Impact		152.1	147.9	156.6	144.3	78.8	679.7
2	Regulatory Income Tax Impact of Nuclear Liabilities Costs and Segregated Fund Contributions		16.5	15.1	18.0	13.9	(7.9)	55.7
3	Revenue Requirement Impact of Nuclear Liabilities Costs	line 1 + line 2	168.6	163.1	174.7	158.2	70.9	735.5
4	Regulatory Income Tax Impact of Nuclear Liabilities Expenditures and Segregated Fund Disbursements	Ex. N1-1-1 Chart 3.2.1, line 16	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)	(214.2)
5	Total Revenue Requirement Impact - Prescribed Facilities	line 3 + line 4	124.2	115.6	137.2	114.3	29.8	521.3
	Bruce Facilities							
6	Pre-Tax Revenue Rrequirement Impact (Impact on Bruce Lease Net Revenues)		144.8	140.5	146.3	154.0	150.9	736.5
7	Regulatory Income Tax Impact		48.3	46.8	48.8	51.3	50.3	245.5
8	Total Revenue Requriement Impact - Bruce Facilities	line 6 + line 7	193.1	187.4	195.1	205.3	201.2	982.1
	Total Nuclear Liabilities							
9	Total Pre-Tax Revenue Requirement Impact	line 1 + line 6	296.9	288.5	302.9	298.2	229.7	1,416.3
10	Total Regulatory Income Tax Impact	line 2 + line 4 + line 7	20.4	14.6	29.3	21.4	1.3	87.0
11	Total Revenue Requirement Impact - Prescribed and Bruce Facilities	line 9 + line 10	317.3	303.0	332.3	319.6	231.0	1,503.3

OPG filed an updated Ex. C2-1-2 on March 22, 2017 to reflect the approved 2017 ONFA Contribution Schedule and actual year-end 2016 financial information. At page 5 of updated Ex. C2-1-2, OPG identified the revenue requirement impacts of these items relative to an earlier Impact Statement (Ex. N1-1-1) dated December 20, 2016 that was based on the company's 2017-2019 Business Plan. As indicated through the exchange at Tr. Vol. 21, p. 44, line 8 to p. 45, line 15, given that these changes became evident at a late stage in the proceeding and were being filed during the oral hearing portion, OPG provided the impacts of these changes in summary form in the updated Ex. C2-1-2 and proposed that they be recorded in the Nuclear Liability Deferral Account and the Bruce

Lease Net Revenues Variance Account (see Ex. C2-1-2, Chart 1A and Ex. C2-1-2, p. 4, line 8 to p. 5, line 15). As indicated through the exchange at Tr. Vol. 21, p. 42, line 10 to p. 43, line 3, subject to the OEB's determination, another option would be to reflect these impacts in the revenue requirement through the Payment Amounts Order process for this proceeding.

For clarity, the updated revenue requirement impact in the above Chart 1 fully encompasses the change in the forecast Bruce Lease net revenues figures from a net cost of $123.3M over 2017-2021 per Ex. N1-1-1, Table 7, line 30 to the updated net cost forecast of $93.5M, consistent with the exchange at Tr. Vol. 20, p. 49, lines 5-27, Tr. Vol. 21, p. 43, lines 11-15 and Tr. Vol. 21, p. 46, lines 9-17. For reference, Attachment 1, Table 1 updates Ex. N1-1-1 Table 7 (Bruce Lease Net Revenues) in line with the most up-to-date changes as shown in the above Chart 1. The difference between $123.3M per Ex. N1-1-1 and $93.5M per Attachment 1, Table 1, line 30 corresponds to the reduction in the cost of the nuclear liabilities reflected in the Bruce Lease net revenues between the most up-to-date Chart 1, line 6 shown above and the equivalent Ex. C2-1-2 Chart 1, line 6.

Numbers may not add due to rounding.

Table 1
Updated Bruce Lease Net Revenues
(Updated Ex. N1-1-1 Table 7)
Years Ending December 31, 2017 to 2021 ($M)

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Revenues:						
1	**Site Services (OPG to Bruce Power)**		0.7	0.7	0.7	0.7	0.7
2	**Low & Intermediate Level Waste Services**		17.8	19.8	19.2	18.6	21.6
3	**Cobalt-60**		0.5	0.5	0.5	0.5	0.5
4	**Total Services Revenue**		19.1	21.0	20.4	19.8	22.8
5	**Fixed (Base) Rent**		24.5	24.8	25.1	25.4	25.7
6	**Supplemental Rent - Non-Derivative Portion**		160.4	153.0	163.0	174.5	140.1
7	**Amortization of Initial Deferred Rent**		12.1	12.1	0.0	0.0	0.0
8	**Total Non-Derivative Rent Revenue**		197.0	189.9	188.1	200.0	165.9
9	**Total Non-Derivative Revenue** (line 4 + line 8)		216.0	210.9	208.5	219.8	188.7
10	**Supplemental Rent - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
11	**Total Revenue** (line 9 + line 10)		216.0	210.9	208.5	219.8	188.7
	Costs:						
12	**Depreciation**		68.6	68.6	68.6	68.4	68.4
13	**Property Tax**		13.0	13.3	13.6	14.0	15.1
14	**Accretion**		458.6	465.7	480.6	495.8	512.4
15	**(Earnings) Losses on Segregated Funds**		(393.0)	(404.3)	(415.6)	(426.2)	(436.0)
16	**Used Fuel Storage and Disposal**		57.0	55.0	59.3	64.2	52.2
17	**Waste Management Variable Expenses and Facilities Removal Costs**		2.5	3.0	2.8	3.4	4.6
18	**Interest**		21.1	24.1	26.7	26.8	25.8
19	**Total Costs Before Income Tax**		227.7	225.4	236.0	246.4	242.5
20	**Income Tax - Current - Non-Derivative Portion**		61.6	58.0	38.5	47.0	41.7
21	**Income Tax - Deferred - Non-Derivative Portion**		(68.1)	(65.1)	(45.3)	(53.6)	(55.1)
22	**Total Income Tax - Non-Derivative Portion**		(6.5)	(7.2)	(6.9)	(6.7)	(13.4)
23	**Total Non-Derivative Costs** (line 19 + line 22)		221.3	218.2	229.1	239.8	229.0
24	**Income Tax - Current - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
25	**Income Tax - Deferred - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
26	**Total Income Tax - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
27	**Total Costs** (line 23 + line 26)		221.3	218.2	229.1	239.8	229.0
28	**Bruce Lease Net Revenues - Non-Derivative Portion** (line 9 - line 23)		(5.2)	(7.3)	(20.6)	(20.0)	(40.3)
29	**Bruce Lease Net Revenues - Derivative Portion** (line 10 - line 26)		0.0	0.0	0.0	0.0	0.0
30	**Total Bruce Lease Net Revenues** (line 28 + line 29)		(5.3)	(7.3)	(20.6)	(20.0)	(40.3)

UNDERTAKING J21.3

Undertaking

To explain $3.1B differential between the ARO liability and the ONFA segregated funds balance at the end of 2016, and if any significant amount of it is the discount rate, to provide the calculation.

Response

Chart 1 below reconciles the noted 2016 year-end $3.1B difference between OPG's nuclear asset retirement obligation ("ARO") balance of $19.1B determined in accordance with US GAAP and the Ontario Nuclear Funds Agreement ("ONFA") Decommissioning Segregated Fund and Used Fuel Segregated Fund (collectively "segregated funds") fully funded balance of $16.0B, as reflected in the company's 2016 audited consolidated financial statements.

As shown below, the difference in the discount rate used to calculate the nuclear ARO and the ONFA funding requirement accounts for approximately $2.2B of the $3.1B differential. The other two notable differences, discussed below, are nuclear liability expenditures that are not funded under the ONFA but included in the ARO, and the inclusion of future waste costs in the ONFA funding that are not recorded in the ARO until such wastes are produced. The calculation of the discount rate difference is provided in Attachment 1.

Chart 1
Reconciliation of 2016 Year-End ARO and ONFA Segregated Funds Balances

Line	Description	Billion $
1	2016 year-end ARO balance	19.1
2	Liability for internally funded expenditures (i.e. not ONFA eligible)	(2.2)
3	ONFA funded portion of ARO balance	16.9
4	Discount rate difference	(2.2)
5	ONFA funding for future wastes not yet generated, which are not included in current ARO balance in accordance with US GAAP	1.0
6	Other	0.3
7	2016 year-end ONFA segregated funds balance	16.0

Internally Funded Expenditures

As noted at Ex. C2-1-2, p. 9, lines 7-10 and discussed by Mr. Mauti at Tr. Vol. 21, p. 75, line 7 to p. 79, line 2, the costs for used fuel management and L&ILW storage costs incurred during the stations' operating lives are not funded under the ONFA and cannot be drawn from the segregated funds. As these costs, referred to as internally funded,

are part of OPG's legal obligation for nuclear waste, they are included in the ARO and are funded from OPG's operating cash flow. Therefore, these costs, which account for approximately $2.2B of the $19.1B of the 2016 year-end ARO balance, are not included in the ONFA segregated funds balance.

Discount Rate

OPG is required to use different discount rates to determine the ARO in accordance with US GAAP and the funding requirement in accordance with the ONFA. As discussed below, the ONFA discount rate is currently 5.15% while the ARO weighted average discount rate is approximately 4.95%.[1] Once internally funded costs are excluded, the discount rate difference accounts for approximately $2.2B of the difference between the ARO balance and the ONFA segregated fund balance at the end of 2016, as calculated in Attachment 1. OPG has no discretion with respect to the use of these discount rates.

The initial value and each subsequent revision to the ARO are known as tranches. As noted at Ex. C2-1-1, p. 4, lines 21-26 and Ex. C2-1-2, p. 7, lines 26-28, in accordance with US GAAP, each tranche is calculated using a discount rate determined at the time of the revision and is not revalued for subsequent changes in the discount rate. As discussed in Ex. L-8.2-1 Staff-207, each upward revision in the amount of undiscounted estimated cash flows underlying the ARO is required to be calculated using a credit-adjusted risk-free rate determined as of the date the revision. As discussed in Ex. N1-1-1, p. 16, lines 11-18, downward revisions in the amount of undiscounted estimated cash flows are required to be calculated using the weighted average discount rate of the existing tranches. Following the year-end 2016 adjustment, OPG's nuclear ARO consists of seven tranches, each with its own discount rate, as shown in Attachment 1. The estimated weighted average discount rate of the seven tranches is approximately 4.95%.

The discount rate used to determine the ONFA funding requirement is determined in accordance with the ONFA, at the time of each approved ONFA reference plan. As explained by Mr. Mauti at Tr. Vol. 21, p. 77, line 3 to p. 77, line 12 and Tr. Vol. 21, p. 149, line 22 to p. 150, line 1, the ONFA discount rate is calculated as 3.25% real rate of return prescribed by the ONFA plus the long-term change in the Ontario consumer price index. The resulting rate stands at 5.15% per the current approved ONFA reference plan and establishes the long-term target rate of return on the ONFA segregated funds.

Future Waste Volume

The ARO balance represents the present value of the obligation for nuclear facilities decommissioning and interim storage and long-term management of nuclear wastes generated to date (in this case, to the end of 2016). As noted at Ex. C2-1-1, p. 4, lines

[1] The difference between the ARO discount rate and the ONFA discount rate were explored in previous OPG proceedings (for example, see EB-2012-0002 Ex. L-1-7 SEC-12).

6-12 and Ex. C2-1-2, p. 7, lines 8-12, these are referred to as committed costs and comprise the ARO liability in accordance with US GAAP.[2] Committed costs exclude incremental variable costs associated with future wastes not yet generated. The ONFA funding requirement accounts for the same obligation as the ARO, plus the estimated cost of the long-term management of future nuclear wastes forecast over the remaining life of OPG-owned nuclear generating stations, in line with assumptions in the approved ONFA reference plan. The inclusion of future waste volume accounts for approximately $1B of the 2016 year-end ONFA segregated fund balance.

[2] As discussed in Ex. C2-1-1, sections 3.2.2 and 3.2.3 and Ex. C2-1-2, p. 8, lines 3-7, additional wastes generated over time give rise to incremental committed costs, which are recorded as increases to the ARO at that time. These costs are referred to variable used fuel and low and intermediate level waste management expenses, the forecasts for which are included in the 2017-2021 proposed revenue requirement as period costs, as they were in previous OPG payment amount proceedings.

CALCULATION OF DISCOUNT RATE DIFFERENCE BETWEEN ARO LIABILITY AND ONFA SEGREGATED FUNDS

ARO Tranche #	Initial ARO and Subsequent ARO Adjustments	ARO Undiscounted Cost Flows (Excluding Internally Funded Expenditures) ($M)	GAAP ARO Discount Rate	GAAP ARO Present Value ($M)	ONFA Discount Rate	Hypothetical ARO Present Value @ ONFA Discount Rate ($M)	Discount Rate Impact ($M)
		(A)	(B)	(C)	(D)	(E)	(F) = (C) less (E)
1	Initial Recognition	56,858	5.75%	12,937	5.15%	14,491	(1,554)
2	Year-End 2006 – 2007 ONFA Reference Plan	120,750	4.60%	1,795	5.15%	1,063	732
3	Beginning of 2010 – Darlington Refurbishment Decision	29,972	4.80%	392	5.15%	241	151
4	Year-End 2011 – 2012 ONFA Reference Plan (Step 1)	(624)	3.43%	(90)	5.15%	200	(290)
5	Year-End 2012 – 2012 ONFA Reference Plan (Step 2) *(incl. Pickering extension)*	17,236	3.50%	852	5.15%	72	780
6	Year-End 2015 – 2015 Bruce Refurbursement Announcement	93,096	3.21%	2,660	5.15%	216	2,444
7	Year-End 2016 – 2017 ONFA Reference Plan	(21,943)	4.95%	(1,629)	5.15%	(1,562)	(67)
	Total			**16,918**		**14,721**	**2,197**

NOTES	
a)	The undiscounted cost flows in Column A exclude all internally funded expenditures as these programs are not part of the ONFA funding requirement. Cost flows associated with variable expenses accrued as additional wastes are generated are recorded in the latest ARO tranche in place at the time the variables expenses are incurred. Undiscounted cost flows in Column A represent projected expenditures over approximately the next 170 years.
b)	Each tranche represents a revision in the amount of undiscounted estimated cost flows underlying the ARO, in accordance with generally accepted accounting principles (GAAP).
c)	As required by GAAP, upward revisions in the amount of undiscounted estimated cost flows (including for internally funded programs) are discounted using the credited-adjusted risk-free rate determined as of the date the revision is recognized, while downward revisions are discounted by the weighed average discount rate of the existing tranche. Although the ONFA-funded year-end 2011 ARO adjustment cost flows decreased, the overall undiscounted cost flows, including internally funded programs, increased. As such, a then-current credited-adjusted risk-free rate was used to discount the incremental cost flows. For the year-end 2016 ARO adjustment, the overall undiscounted cost flows, including internally funded programs, decreased. As such, the weighted average rate of the existing tranches was used to discount the cash flow decrement (as noted in Ex. N1-1-1, p. 16, lines 11-18).
d)	To derive Column E, Column A cost flows are discounted by the ONFA discount rate in Column D.

UNDERTAKING J21.4

Undertaking

To confirm whether any of the projects on Ex. D2-1-3, Attachment 1, Section 3.0, are CRVA eligible.

Response

OPG confirms that the projects listed at Ex. D2-1-3, Attachment 1, Section 3.0 are not eligible for CRVA treatment. OPG has provided the list of CRVA eligible project for the nuclear business in response to 4.1-Staff-024.

UNDERTAKING J22.1

Undertaking

To provide the revenue requirement impact of AHS & OSB, including the year.

Response

Based on forecast capital in-service additions for the Auxiliary Heating System (AHS) project of $94.2M in 2016 and $0.1M in 2017 (Ex. D2-1-3 Table 1, line 11, cols. (k) and (l), respectively), the estimated nuclear revenue requirement impact for the project is approximately $11M in 2017, $9M in 2018, $8M in 2019, and $9M in each of 2020 and 2021.

For the Operations Support Building (OSB), the estimated nuclear revenue requirement impact is approximately $6M in 2017 and $5M in each of 2018 to 2021, based on $55.1M placed in service in 2015 (Ex. D2-1-3, p. 10, line 26) and $3.6M forecast to be placed in service in 2016 (Ex. D2-1-3 Table 1, line 2, col. (k)).

The above estimates include income tax impacts related to capital cost allowance deductions and were otherwise derived using the same approach used in Ex. N2-1-1 for the Heavy Water Storage and Drum Handling Facility Project, including the impact on regulatory tax loss carryback.

UNDERTAKING J22.2

Undertaking

To calculate, making any appropriate assumptions, the total interest costs on amounts being deferred during this IR period.

Response

The total interest cost associated with the $1,005M that OPG has proposed to defer in the 2017-2021 period is approximately $470M over the life of the current rate smoothing proposal. OPG has applied a "first in, first out" approach to interest costs and has assumed that since the $1,005M is the first amount to be deferred, it will also be the first amount to be recovered. Based on the projections of deferrals shown in N3-1-1, Attachment 2, Table 19, this calculation assumes that the $1,005M deferred would be recovered by mid-2029.

UNDERTAKING J23.1

Undertaking

TO DO A CALCULATION TO SHOW THE IMPACT SHOULD THE BOARD CHOOSE AN EFFECTIVE DATE OF SEPTEMBER 1ST.

Response

OPG disagrees that September 1st would be a reasonable effective date; however, if the OEB were to approve both an effective date and implementation date of September 1st, 2017 , OPG would continue to collect its interim payment amounts for the nuclear and regulated hydroelectric facilities until August 31st, 2017. Beginning on September 1st, OPG would begin collecting the payment amounts and rate riders approved by the OEB in their EB-2016-0152 decision and order. In this scenario, OPG will have under collected its nuclear payment amount by approximately $435M (incremental to amounts that OPG has proposed to record in the RSDA through the proposed WAPA and associated nuclear payment amount), and its hydroelectric payment amount by approximately $14M.

As stated at Tr. Vol. 23, pp.26-27, this scenario assumes that the OEB approves the full year revenue requirement as requested by OPG for 2017-2021. As such, OPG would record in the RSDA the difference between the approved nuclear revenue requirement and the interim nuclear payment amounts for the period from January 1st, 2017 to August 31st, 2017, and the difference between the approved nuclear revenue requirement and the smoothed nuclear payment amounts on a WAPA basis as approved by the OEB from September 1st, 2017 to December 31st, 2017.