EB-2016-0152

OEB Staff Compendium

Panel 1 A

PROGRAM SCHEDULE

1.0 OVERVIEW

The ability to validate, integrate, oversee and ultimately to retain control over the program schedule is one of the key factors that has driven OPG's Darlington Refurbishment Program ("DRP") strategy. OPG has developed a fully integrated Program schedule, which incorporates the project schedules for each of the major work bundles that are detailed down to the individual work packages or components within each bundle. OPG is in a position to effectively leverage the control it retains over the Program schedule to ensure Program success since the schedule has a direct impact on Program costs. This schedule describes (1) the manner in which OPG developed its integrated Program schedule, (2) OPG's multi-level scheduling approach, (3) the Unit 2 critical path, and (4) the difference between the schedule that is being used as the Program control schedule and the planned outage duration.

2.0 SCHEDULE DEVELOPMENT

Establishing an accurate and realistic schedule is a critical planning tool for the DRP. The schedule reflects the sum total of the estimated duration of the individual tasks included within the Program scope. The schedule is critical to properly strategize, plan and prepare for upcoming project work, to determine resource requirements, to understand how work is progressing and to apply corrective actions if required.

OPG and its contractors have developed schedules with inputs from appropriate project stakeholders. Scheduling includes:

- the scope of work to be completed;
- identification of key activities including their start and finish date, duration and resources;
- the sequence and logical interrelationship of activities and milestones;
- identification and optimization of the critical path;
- regular monitoring and updating to track performance, forecasting, and initiate corrective action for schedule threats; and

- look ahead at planning and strategizing to identify and manage priorities, opportunities, and threats.

The overall planning and scheduling process can be represented in two major stages: (1) the formation of a baseline schedule; and (2) schedule management, including monitoring, analysis, reporting, and mitigation.

This Ex. D2-2-6 focuses on schedule formation and Ex. D2-2-9 focuses on schedule management. OPG project teams have established a breakdown of work that is deliverable-oriented and which addresses 100 per cent of project work, down to the individual work components that make up a bundle (also referred to as “work packages”). The work breakdown reflects the corresponding contracting strategies so that work scope, budgets and responsibilities are clearly allocated.

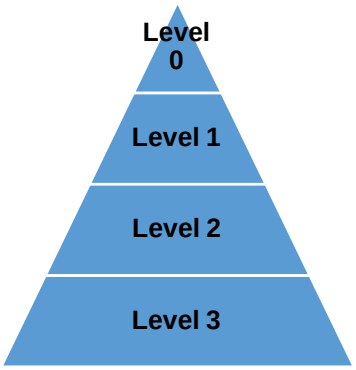
The project schedules have been reviewed for overall quality to ensure they meet process requirements. These reviews will be performed on a regular basis as part of normal updating of the schedule. Furthermore, the schedules have been reviewed through an iterative process and approved by the project team members and key project stakeholders. These reviews considered project and Program constraints, milestones, resource requirements, and critical path to determine the acceptability of the schedule.

3.0 MULTI-LEVEL SCHEDULING APPROACH

Based on recommended practices, OPG has established its schedule using a multi-level scheduling approach. As shown in Figure 1 below, project schedules are prepared with up to four levels of detail, from Level “0”, which contains the Program milestones managed by OPG which identify the major deliverables and timelines for the overall DRP , to Level “3”, which contains the greatest level of detail showing individual work components at the task level. For example, projects where most of the work will be performed by contractors utilize detailed Level 3 schedules. OPG as the owner performs project management and control activities utilizing Level 0 to 2 schedules.

Figure 1

Multi-level Scheduling Framework[1]



Level 0: Nuclear Program Milestone Schedule, controlled by OPG Senior Management.
Level 1: Nuclear Program Integrated Master Schedule, controlled by OPG Senior Management. Program Level 1 contains all Control Accounts from all Projects as well as for Program Management work.
Level 2: Nuclear Program Coordination & Control Schedules, controlled by OPG Nuclear Program/Project teams. Program Level 2 contains all Work Packages in the Program and they are interrelated.
Level 3: Nuclear Project Detailed Production Schedules, controlled at the project level, by contractors or OPG (for OPG executed projects).

Level 0 consists of the *Nuclear Program/Project Milestone Schedule*, and is used by OPG senior management to provide the basis for establishing the master schedule. This includes program release milestones, regulatory milestones, outage preparation milestones and outage execution milestones.

The Level 1 schedule is the *Nuclear Program/Project Integrated Master Schedule* that contains particular work scopes, a time window and a responsible organization. The Level 1 schedule provides a high-level management summary of the Program or project, represents all units, phases and bundles, and is used by project managers, contractors and scheduling functions.

Level 2 schedules are the *Nuclear Program/Project Coordination & Control Schedules*. This is the schedule used by OPG to track the overall status of the Program. It will be updated and controlled by OPG and is based on the contractors' detailed Level 3 schedules.

Level 3 schedules are *Nuclear Program/Project Detailed Production Schedules* which further break down work into detailed activities. Level 3 schedules are prepared by the group

[1] A Level 1 schedule is comprised of Control Accounts, which represent high level execution windows in each outage segment. A Level 2 schedule is comprised of Work Packages, which are used to integrate costs and schedule as well as provide grouping for related Level 3 activities. Earned Value Management is done at this level.

executing the work (typically by contractors, and in some cases by OPG where OPG is self-performing work). The lowest level of tasks to be executed are developed here.

Once approved, schedules are 'baselined' by the project owners as a benchmark for measuring implementation performance. Baselined schedules are archived and will not be modified, except by means of a re-baselining process involving cost and schedule analysis and only through authorized change control. This process is discussed in Ex. D2-2-9.

4.0 CRITICAL PATH AND SCHEDULE OVERVIEW

The critical path refers to the longest sequence of activities in a project plan which must be completed on time for the timely delivery of the overall project. Activities on the critical path cannot be started until one or more predecessor activities are complete. If the critical path is delayed for one day, the entire project will be delayed for one day unless the critical path activities following the delay are completed one day earlier than planned or future critical path activities are forecast to be completed earlier than the original plan.

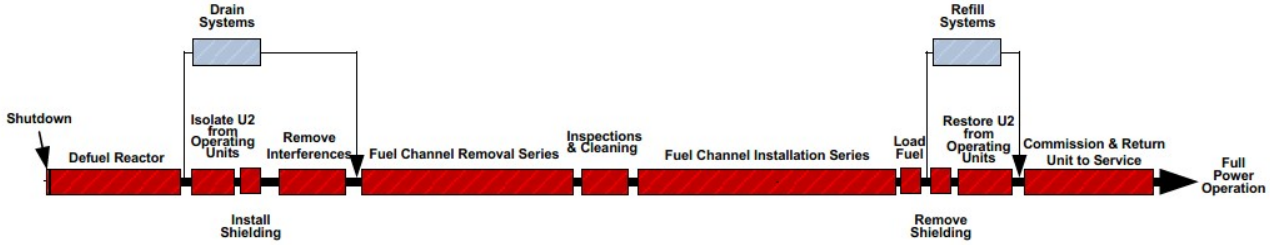
Figure 2 presents a simplified outage schedule and illustrates the major phases for the execution of Unit 2. The phases are:

- Reactor shutdown
- Defuel reactor
- Drain systems and isolate from containment
- Fuel channel removal, inspection and cleaning and installation
- Refuel
- Refill and re-establish normal containment boundary
- Commission and return to service

A more detailed schedule for Unit 2 is provided in Attachment 1.

Figure 2

Simplified Unit 2 Refurbishment Outage Schedule



5.0 PLANNED OUTAGE DURATION VERSUS HIGH CONFIDENCE SCHEDULE

As part of the schedule development process, OPG has integrated all contractor schedules, determined the critical path and created the schedule provided in Attachment 1 for the Unit 2 critical path. This is the planned outage duration and OPG will manage day-to-day performance using this schedule. It will also be used to determine contractor incentives and disincentives, where applicable.

OPG also evaluated risks and uncertainties for each segment of the schedule, and determined the amount of contingency required to deliver the Unit 2 refurbishment in consideration of the risks and uncertainties evaluated. This resulted in the production of a schedule that includes contingency for certain schedule risks that may be encountered during the execution of the refurbishment outages. Through probabilistic analysis, OPG expects to execute the Unit 2 refurbishment within this schedule. This high confidence schedule is the basis for Release Quality Estimate ("RQE"), which is the program level control budget. This schedule is also the schedule from which project success will be assessed.

As discussed in Ex. A1-3-3, if refurbishment of Unit 2 is completed earlier or later than scheduled, production may vary. In addition, there is a risk that the post-refurbishment forced loss rate at Darlington may vary from OPG's current forecast. These factors have the potential to either decrease or increase production, depending on the circumstances. Given the long term of this application and the uncertainty of nuclear production during that period,

a mid-term review of nuclear production and related fuel costs for the second half of the application term (i.e., July 1, 2019 to December 31, 2021) would help address the forecast uncertainty inherent in OPG's production forecast as it looks further into the future and provides a basis to set reasonable production performance targets for the second half of the application term.

ATTACHMENTS

Attachment 1: Project Schedule Diagram

DARLINGTON REFURBISHMENT
Repowering Ontario

UNIT 2 Refurbishment Outage

UNIT2 REVB
November 15, 2015

Critical Path Windows
Close to Critical Path/Low Float Windows
Electrical Windows
Turbine/Generator
U4 Outage 2019 (D1941)
Tnoum Removal Faaility Gas Outage
DNGS Planned Outages
Tritium Removal Facility Planned Activities

OCT 2016 | NOV 2016 | DEC 2016 | JAN 2017 | FEB 2017 | MAR 2017 | APR 2017 | MAY 2017 | JUN 2017 | JUL 2017 | AUG 2017 | SEP 2017 | OCT 2017 | NOV 2017 | DEC 2017 | JAN 2018 | FEB 2018 | MAR 2018 | APR 2018 | MAY 2018 | JUN 2018 | JUL 2018 | AUG 2018 | SEP 2018 | OCT 2018 | NOV 2018 | DEC 2018 | JAN 2019 | FEB 2019 | MAR 2019 | APR 2019 | MAY 2019 | JUNE 2019 | JUL 2019 | AUG 2019 | SEP 2019

Outage Day: 0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300 320 340 360 380 400 420 440 460 480 500 520 540 560 580 600 620 640 660 680 700 720 740 760 780 800 820 840 860 880 900 920 940 960 980 1000 1020 1040 1060

LEAD IN SEGMENT | REMOVAL SEGMENT | INSTALL SEGMENT | LEAD OUT SEGMENT

U1 Outage 2017 (D1711)
TRF - Cryogenic Systems Only
Short upgrader outage possible during TRF outage

U3 Outage 2018 (D1831)

Tritium Removal Facility Gas Outage

U4 Outage 2019 (D1941)

Conventional Side Layup
002

100 Feedwater/TG and Condenser Scope Phase 1

081 Turbine Generator Major Overhaul

Resource Holdout

Bulkhead Installed & D1711 Complete

Power Track 3/4 Replacement
052
** IPG schedule Fuel Handling coordination required

Power Track 1/2 Replacement Window 1
039
To D1831
** IPG schedule Fuel Handling coordination required

From D1831
Power Track 1/2 Replacement Window 2
047
** IPG schedule Fuel Handling coordination required

Hold out until 6 months before ATC
LZCS Rehab
032
To RCHP 5

ECI Valve Maintenance
147

ECI Vault Work
128

SG Lay-Up Primary Side
034

Primary Side SG Clean & Inspect
West Side SGs | East Side SGs
062

VVRS Mods and Rehab
009

HTS Aux Vac Dry
035

HTS Auxiliaries - Drain Dead Legs & Purge & HTS Rehab Scope Outside Vault
048

Note: PHT Motors and Steam Generators parallel work constraint (hoist way conflicts)

Reactor Area Crane not available during Class 4 Electrical Maintenance Window

Pressure Tube Install progressed to below Row M

068
Complete Emergency Heat Sink pipework (East Vault)

To RCHP 4

Airlock Mtce & Testing
006

HTS must be depressurized to start PHT motor replacement

PHT PM1 & PM3 Motor Swaps
060

PHT PM2 Motor Swap

NOTE:
1) PHT Pump Motor Swaps logic under development due to motor delivery dates and duration of window for each motor and duration between each motor replacement.
2) Vault work constraint with reactor area crane lifts to be resolved.

RCHP 1
Temp Fission Chamber Install
129

013 PHT Bulk Drain
HTS Vac Dry 40d
029
Vac Dry (Cont'd)

To Tie-in for Moderator Vac Dry

Remove Mod Dry Equip & Reconnect Mod Pipework
078

Cold Testing & Establish GSS
081

079 Gross Air Leak Test
080 Fill Calandria

Earliest Date To Credit TCB 30 days on U1 SD timer or U1 STOP Mods complete.

104 Vault Projects

to Moderator Drain

Vault ACU Replacements
West Side
064
East Side
070

To Window 68 Emergency Heatsink pipework in East Vault must be installed post ACU work

Inspection Series
Tube Sheet Bore Cleaning

085 Airlocks Closed & Pressure Test

OPG Bulkhead Postreqs

Heat-up & Low Power Testing

Run-up & Sync & Balance

RCHP 2
RCHP 3
RCHP 5
RCHP 8

STOP
U2 SD 1d

Defuel Reactor
113 days

Install Bulkhead
38

Bulk Interference Removals
19 | 24

Feeder Cabinet Removal
44

Feeder Removal
38

Dummy FB Removal
28

PT Sever
9 | 16

Sever Bellows
33

End Fitting Removal
36

PT Removal
37

CTI Release
14 | 14

CTI Removal
32

Calandria Tube Install Series
101

Pressure Tube Install
18 | 125

Lower Feeder Install Series
85

Fuel Load
20

RTP Removals, Bridge Replacement
67

Bulkhead Removal
26

Fuel Channel Removal Series

Remove FM Bridges & Install RTPs

Nozzle Inspection & Weld Prep
045

076 Upper Feeder Installation (180 days)

To S/G Primary Side Inspections

Trial CT Install

Bellows Inspections

NPC Logic Restoration

ATC

Power Escalation

High Power Testing & Turbine Testing

RCHP 6
RCHP 7

015 Crane Maintenance 2d
017 Install End Fitting Caps

024 Containment Pre-test, Achieve Dew pt. & Containment Test

008 -Final Commissioning VVRS Phase 1 -AL & TCD Logic Mods -BU Logic Mods Phase 2

Install Shielding

Replace Adjuster Rods
021

Hold out for 28 d training period

028 Replace Vertical Flux Detector

073 HFD Replacements

To Remove Mod Dry Equip.

SDS1/2 Computer Testing & Partial AFS

SDS1/2 Computer Replacements
007
Logic Hold Out For Project Readiness

Isolate Calandria From Main Pipework & Hookup Drying Equip.

Mod Drain & Flush

Establish Upper Calandria Purge Flow & E/W Valve Maintenance

BU16 Maintenance
125
To VVRS Commissioning & Odd Electrical Outage

from HTS Vac Dry Complete
038 | 108 | 103

LISS Rehab
046

To Remove Mod Dry Equip.

PHT PM4 Motor Swap
Hold out for motor refurbishment availability

RCHP 4

089 090
29 | 14
HTS Air Hold, Fill & Hydro Test
HTS Operational Testing

Instrument Air Mtce
Hold out to summer of 2018
054

from HTS Auxiliaries Vac Dry Complete
067
Tie in HTS Vac Dry Skid to Mod Pipework

121 Vac Dry Lower Moderator Pipe work

122 Moderator Valve Rehab

Remove Vac Dry Equip

123 SDC Rm Work (Purge, New Aux SDC Pumps, SDC Valve work)
124

Must be completed before HTS Fill

126 127
T9/T11 T10/T12 Maintenance
(TPDS Tie-ins completed as pre-requisites)

To TPDS & Odd Electrical Outage

022
HTS PM1 & PM3 Removal

EPS MCC Rehab
005
Resource Tied to Class III Elec Mtce Work

041
Class 3 Electrical Maintenance

Class 2 Elec. Maintenance
A | B | C
040 | 043 | 044

To RCHP 1 Mod Fill

Reactor Area Crane not available during Class 4 Electrical Maintenance Window

Hold out for system Configuration & Vault Projects Window Complete

CL 4 Electrical Maintenance
051

MOT/UST/IPB Rehab
004

To RCHP 5

LPSW Outage
057

ESW Rehab Winter 2018 (need cold water temps)
053
Must be completed before HTS heat-up

Hold out for Cooler Temperatures

PULSW Outage
056

PULSW SDC Supply Line Replacement Outage
148

055
CCW Rehab

Must be completed before HTS heat-up

Must be completed before HTS heat-up and SG Primary Side Windows

D1711 BO Work Complete & Cooldown After Vac Dry(14d)

Secondary Side SG Layup
003

Secondary Side SG Clean & Install Access Ports
037

State 1 | State 2 | State 3a | State 3b | 60% RFR Complete | State 4a | State 4b | State 5

REVB NOTE: REVB Schedule (P6) and this Level 1 have been published and documented on November 15, 2015. Note that all schedule logic and level 3 schedules are not yet finalized and are still in development for Unit 2. Therefore, this schedule and window durations are subject to change within the Unit 2 bounding duration as per the approved Release Quality Estimate, approved in November 2015. All changes to this published REVB will be documented by the U2 Outage Manager.

RCHP X Reactor Control Hold Point
STOP Reactor State Transition Requires Approval to Proceed

Reactor States
State 1: Reactor Shutdown Evolution
State 2: Guaranteed Shutdown with Irradiated Fuel Core
State 3a: Defueled State
State 3b: Defueled & Isolated from Containment State
State 4a: Non Irradiated Fuel & Isolated from Containment S
State 4b: Non Irradiated Fuel State
State 5: Approach to Critical & Return to Service State

REVB APPROVALS TO ISSUE

Prepared by: 5-Nov-15
Dan Sawyer, U2 Outage Manager

Reviewed by: 15-Nov-15
Karen Fritz, U2 Outage Director

Concurred by: *REQUIRED FOR REV C*
Boris Vulanovic, Refurbishment DOM

Approved by: *REQUIRED FOR REV C*
Mike Allen, VP Refurbishment Execution

Refurbishment Construction Review Board Review July 18 - 22, 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 July 18 through July 22, 2016. This report is based on document reviews during the preparation for the review, interviews with Refurbishment personnel, and plant walk-downs during four days of the onsite visit.

The RCRB provides a report of its activities to the President Nuclear and Chief Nuclear Officer, which includes both observations and recommendations to improve performance.

The RCRB team consisted of the following members:

External members:

Ken Ellis Drew
Fetters Britt
McKinney
Mike Rencheck
Ike Zeringue

Internal member:
Paul Pasquet

The RCRB would like to recognize the excellent support provided by Jennifer Vulanovic, Irena Doslo, and Graem Meteer; 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 briefing during the next visit to ensure progress is being made.

Executive Summary:

It is clear to the RCRB that progress has been made getting "ready to execute" the refurbishment project at Darlington Station. The team is impressed with the collaboration and level of preparations associated with the Fuel Handling readiness for defueling, turbine generator work, and the Re-tube Feeder Replacement (RFR) project. Likewise, other support aspects such as the project "material staging" facility is world class and is one of the best organized and laid out facilities that the RCRB has seen.

Key Issues and recommendations:

There are a number of issues that require prompt attention by the refurbishment leadership team given there is less than 3 months to breaker open on the unit entering its refurbishment outage.

1. Currently, the execution of the pre-requisite refurbishment work is behind schedule and a "bow wave" of activities is starting to occur. Only 21 of 67 prerequisite work windows are complete or on schedule, the remainder are delayed.

A work completion rate of approximately 150 tasks per week is currently being completed. A rate of 2 to 3 times that will be needed to complete the prerequisite work prior to the shutdown of the unit. In addition, execution of some of the planned work is progressing more slowly than expected due to the complexity of the work, late discovery, or late identification of issues (e.g. Shutdown Cooling HX replacements).

Portions of this work is key to the start of the project and has completion dates that are 'just in time' for their use. The current schedule for a number of the prerequisite activities have little float. For example:

- The construction of the waste processing building, which is required to receive re-tube waste has little float.
- The sequence of Shutdown Cooling HX replacement, Primary Heat Transport System heavy water transfer header maintenance, and the unbudgeted outage to address the STOP modification short-falls will require good co-ordination and has little schedule float.

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.

It was noted during the review week that no routine "T+1" type meeting is held to both identify and rectify schedule challenges and hold staff accountable for achieving the schedule. Carrying out schedule reviews may partially rectify this issue.

2. The level of readiness to execute the project is most advanced in the 'lead-in segment' (but decreases with subsequent segments), for example;
    - The level of preparation, teamwork, and ownership for the reactor defueling appears to be good.
    - The level of preparation for the installation of the 'bulkhead' appears adequate.
    - The RFR component of the 'removal segment' (removal of reactor components such as pressure tubes etc) appears to be well planned. The use of the mock-up is a valuable tool, and is being used to practice and to perform tool testing.

Work activities such as the Heat Transport Pump motor movement (currently a requirement exists to stop work in the reactor vault while hoisting motors) and the currently planned radiography in the reactor vault could still impact the critical path schedule, and have not been resolved. (Note, this is not an all inclusive list).

3. Project preparation, planning, and scheduling is incomplete in part due to the processes and infrastructure to close-out the construction work, complete the necessary documentation reviews, and then plan and execute the commissioning and "return to service" activities are not well advanced. Scheduling the return of plant systems should govern how the construction work is sequenced. Failure to follow this pattern will result in having to revise the schedule and add to the required resources to complete the schedule. ***The RCRB considers this crucial to the success of the project.***

Once the unit is shut down and defueling is commenced, the RCRB is concerned about the organization's ability to manage the challenges of execution while completing return to service planning. Key resources such as availability of certified staff with project experience will be at a premium. In addition, with all the issues that the management team currently has to manage (for example the need to develop mitigation plans for potentially late campus plan projects), then add the inevitable discovery issues with a shutdown unit in the execution phase. It is critical for the success of the project that these issues are resolved in a timely manner.

Recommendation #2

a) 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 (with quality and ensuring that gaps do not exist which demonstrate the work was completed as specified). There is considerable project related OPEX to support the formation of this group or function. Currently within the "Projects and Modifications" group, elements of this function currently exist and could be modelled.

b) As discussed above, a return to service group needs to expeditiously complete both the conceptual and detailed planning associated with returning of layed up / operating and modification systems and components to service. This activity needs to be monitored and tracked by the Refurbishment management team.

4. During the RCRB review a number of reports with associated metrics were reviewed. In a number of cases it was difficult to determine how these metrics rolled up to the refurbishment score card.

Recommendation #3

While the project does have a large number of metrics, they do not consistently provide an accurate, 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. The RCRB recommends on a priority basis, the following changes be made to the existing metric set:

- Where qualitative measures of readiness are used, Management needs to ensure a challenge process exists to ensure the rating chosen reflects the true level of readiness.
- As was discussed during the on site visit, individual departments need to produce "score cards" supported by metrics which roll up to an "overall refurbishment" score card.

5. Currently, the project is being managed from the 'online' operational perspective. It is being viewed as a 'very large planned outage' using traditional outage processes. From experience on past refurbishment projects, the RCRB views this as a significant challenge to efficiently use those processes to manage the project, given the scale of work being planned and executed.

   The "operational model" for this project needs to change, and be based on: eliminating unnecessary reviews and approvals, streamlining of processes to support work execution, and only requiring operational involvement where value is added. In addition, except for OP&P revisions, there have been few requests for relief on reactor safety constraints (e.g. SLOD, Single Line of Defence) from Refurbishment staff.

   There are a number of interface issues between the site and the project that needs to be resolved, and are well behind when they should have been decided. These are adversely affecting the organization's ability to obtain clarity on standards and expectations associated with execution of the project.

Recommendation # 4

One of the fundamental premises of a strong culture is to ensure that written expectations exist; staff need to understand the expectations and then follow them. In addition, with the reactor defueled and the unit separated from containment there exists a once in the life of the operating unit an opportunity to streamline the work processes so only those that truly add value (be it from a safety / quality / schedule or cost perspective) are in effect. In order to achieve these two basic principles a team needs to be struck utilizing personnel with external project experience to do the following:

- Review the expectations associated with the execution of work (be it approvals to go to work / approvals to modify work instructions / modify designs packages / expectations for how work is carried out etc)
- Identify the value added components (and eliminate the non value added components)
- Look to minimize the operational constraints and constraints posed by operations personnel
- Obtain craft and vender input as to what constraints appear not to be adding value
- Ensure that constraints that may be relaxed are taken into account in the return to service process
- Produce a refurbishment document set for staff to follow defining the expectations for doing work and when they apply (which phase or segment in the project they apply). In addition transition plans need to be in place to move between project work segments (as referenced in the level 1 project plan) or between states as referenced in the Operating policies and principles.

6. There is a cultural tolerance for acceptance of work delays. This tolerance for work delays is being enabled by the leadership team. There is a lack of understanding for what it means to be an 'accountable organization.' Example:
   - Project pre-requisite milestones have moved multiple times
   - Currently no T+1 nor "schedule adherence" accountability meetings exist.

Recommendation # 5

As discussed is this report both in this section and in the observations section, the level of accountability and understanding of what accountability means must be improved on the project. This includes a common understanding by both OPG staff and the contract partners of what it means to be an accountable organization. The RCRB is not suggesting that a management style be implemented that is not consistent with the culture of OPG. OPG does have stated norms and expectations when it comes to accountability and has examples where people and organizations

do demonstrate the required behaviours. The leadership team needs to ensure what is expected is clearly understood, then modeled by the leadership team and subsequently re-enforced and coached.

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. Failure to have a high level of readiness including having the processes whereby work is executed and closed out, can put the project at risk.

It is the view of the RCRB that unless the appropriate amount of progress is made resolving these 5 recommendations, a significant impact to the project schedule and cost will occur.

Observations

During the course of the review week, a large number of observations and interviews were carried out. Outlined below are a number of insights.

1. Refurbishment Work Processes:

   The refurbishment project is currently being planned, controlled and scheduled as a "large planned outage." This is not recommended by the RCRB. If OPG determines that it is to be performed as a large 'normal plant process' outage, then the current refurbishment schedule is at risk. Change processes (for CWPs/work plans/ ITPs/ field changes, etc.) need to be streamlined. The RCRB recommends that the process is flow-charted, and the non-value-added steps removed. In addition, the process expectations must be clearly communicated.

   - An example of the inefficiencies noted above was found regarding the use of the OPG guidance document associated with making field changes. The relocation of an EQ label on a junction box using the contractor engineering vendors to process this change was estimated to cost upwards of $10K. This document serves as a guide for when field changes are to be used and are clearly inappropriate.
   - The vendor/OPG work flow is not aligned to common goal or methodology. (For example, it was unclear if work reports were to be used on the project).
   - Managing of field changes, CWPs is not fully vetted and tested for efficiency.
   - TSSA involvement must be clearly identified and co-ordinated. Indications are that it has not been fully considered and needs further development.
   - The Expedited Material Acquisition process needs to be streamlined. Only associated "value-added" activities should be mandated.
   - The vendors openly state the current processes are placing stress on their ability to complete work. These remarks have not been dealt with appropriately (or dispositioned) by OPG.
   - Engineering will have 10 resident engineers with design authority. The JV are being directed to utilize this concept as well. This is seen as positive by the RCRB.

2. A fully staffed commissioning group must be put in place:

    - Operations clarity regarding Return to Service (RTS) is still outstanding, and lacks a clear direction (RTS philosophy is not decided). Construction work must be sequenced based on the methodology of the RTS. Currently, there is effectively no RTS group (staffing of this group does not appear to be a priority). There is a small effort being done informally via spreadsheets, which is not part of the Work Control Process. Integration of equipment and systems that will be in 'layup' conditions have not been considered as part of the RTS thought process, but need to be integrated. 'Layup' equipment is being viewed as 'normal outage restoration.' The use of 'partial' versus 'fully compete' system or equipment turnover is not decided.
    - The philosophy of "What does the end state of the project look like" still needs to be documented. RTS activities are not scheduled yet.
    - Communication to the Operation staff on how decisions will be made, or what priorities or philosophies the staff needs to follow and is substantially behind.
    - Metrics are not developed around the key commissioning/RTS activities.

3. Culture: Sense of urgency & accountability:

    - The station needs to articulate and enforce what success looks like associated with accountability. Very simply: do what you say you are going to do, when you say you are going to do it, and do it with the requisite quality. The leadership team lacks the "discipline" to re-enforce the needed attributes associated with accountability.
    - Management behaviour when Schedule expectations are missed is weak. The prevailing 'discussion' at a meeting is focused on when the new target completion date is, but little to no discussion as to why was it missed, why was there no previous warnings or requests for assistance, why there was not a previous recovery plan to ensure the target completion date would not be missed, what is the cumulative impact of the delay on both the project and colleagues, what follow-up is needed, who needs to rally around mitigating the negative impact of the delay, who has overall ownership or corrective action.
    - Any 'enforcement' that does occur is driven by meetings (not process), and the lessons learned appear to be forgotten going forward.
    - "Accordion" was a word used to describe the current scheduled activities. There is a perception that there is still the four month 'defueling window' to plan and execute work before "real" outage starts. Thus there appears to be a perceived 'four-month float' in the work, and conversely little importance (or belief) placed on schedule discipline.

- Further examples of being comfortable (tolerance, willingness to use up schedule float):
    i. EPG3 – work completion is very tight, but there is also a very complicated testing sequence. This project is at risk of not meeting the date committed to CNSC.
    ii. D_2O storage building – looking at November for piping fully installed. The fully complete date is currently scheduled for April 2017. This date has slipped, substantially. The RTS need by date is also April 2017. If completed as scheduled, it will have zero margin.
- In short, both the management team and the contract partners need to make it very uncomfortable for those who do not deliver on their commitments, and offer support wherever they can to get the commitments back on track. That will be the commencement of a true team.

4. Organizational interface:

Both the project and the station have aggressive work programs, performance targets and objectives to achieve. In some cases, these objectives may result in competing priorities that need to be managed. During interviews it was apparent that in some cases, issues may not 'bubble-up' to the right level and the right decision maker. This is needed in order to set the proper priorities. As a consequence, issues may be lingering at a lower management level in the organization for longer periods of time than they should be. An organization with an execution mindset can't allow these types of issues to languish.

Three different types of organization models can be used for the refurbishment project being executed at Darlington:

1. There is a senior leader on the DN site who is accountable for all day-to-day and long-term activity going on at the site.
2. The project is essentially self-contained and antonymous, and does not rely on the other organizations for services etc.
3. The project organization reports to a higher level in the organization.

Currently, a hybrid organization exists which relies on a significant level of alignment, interaction, mutual support, and teamwork. The current approach is not yet mature, and may be difficult to sustain going forward. Clearly, 100% autonomy is not possible. The RCRB is suggesting that a review of how the project is interfacing with the plant, as well as what should be the role of Operations, needs to be periodically reviewed.

5. Resourcing:

The project has created a group to support line managers in completing and initiating the hiring process (be it augmented or regular staffing) which reduces the workload on the line managers. This is seen as a positive by the Project Managers and by the RCRB. Metrics associated with the hiring and security clearance process exist, and are reviewed at senior oversight forums. Very recently a list of priority positions (on the order of approximately 130 positions) required to support project execution has been identified and is currently being addressed (of the 250 total positions needed). The project may wish to further prioritise the 130 to ensure the most critical resources are secured first. Once the hiring is completed, the line organization will need to assimilate and train these individuals.

The resourcing plans and their performance will continue to be a focus area for the RCRB. At this point plans appear to be in place, but results need to be demonstrated.

6. [redacted]

Overall, [redacted] performance has not been consistent. This contractor will need to be closely monitored and additional support maybe required. [redacted] This has resulted in additional interfaces to be managed, as well as quality challenges, on some projects. Listed below are a number of observations associated with the Vendor:

- [redacted] currently is not stocking commodities in their warehouse to timely resolve installation problems.
- At the T-2 schedule meeting a number of [redacted] jobs were pushed out due to lack of resources.

7. Project Meetings:

Time management within the project organization (this applies to OPG staff and the requirements OPG places on its Vendors) needs to transition to an 'execution focus.' Once the breaker opens, the need to be concise, ensure adequate time is spent overseeing field activities, and being able to strategically look ahead, will be very important. In addition, it appears that repetitive 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 not be adding a lot of value.

- As an example, during the "Change control meeting," there were 20 plus people involved in the decision making associated with relatively small amounts of money and no

schedule impact. A review by the appropriate person with a single sign-off would be sufficient.

- Management needs to utilize the "delegation of work" work model where there is efficient use of managers' time (minimize non-value-added meetings). The project now needs to be focused on the Critical Path and Overall Schedule, as opposed to which meetings to attend.
- There were over 50 people in the PCC meeting. This may be too large a group with too little value for most of them. Other methods of communication and information sharing could be used.
- The RCRB believes it would prove very beneficial if the organization rationalised and reduced both the multitude of regular meetings, and their attendees, thereby facilitating more time for the management team to focus on execution activities.

8. Plant Walk-downs and general observations:

    - Maintenance staffing looks insufficient, or has 'just-in-time' transfer dates. The RCRB did not have time to focus on this issue to understand how the OPG maintenance work component of the outage is being managed, but the number of maintenance personnel assigned to the project (~ 50) looks low based on our experience.
    - Housekeeping in the plant has improved.
    - The designated walkway has not yet been painted which "corrals" contractors entering and walking through the building, and directs flow through protected areas. The RCRB understands the floor pathway painting is scheduled shortly.
    - Hand and Foot monitor for interzonal monitoring was broken (again), with no redundant instrumentation installed or contact information given. During the project this type of infrastructure support short fall can be a significant issue for trades getting to work.
    - Several aspects of islanding have progressed such as defining boundary points, and CBTs for different stakeholders has been developed. Islanding needs to take into account the return to service aspects of the project to support construction completion and testing**.** . It took the RCRB numerous meetings to try to get to understand to overall picture, and it is fair to say the RCRB still does not fully understand it, nor do a multitude of station staff. Failure to properly communicate this to affected parties would be yet another issue and challenge for the Management team and is crucial to the successs of the project.
    - The location of additional service air compressors have been marked in the four units, but installation has not yet started. Regarding Unit 2, concrete pedestals have been poured but that is the extent of the installation. Given the time frame from now to

breaker open, the installation of the Unit 2 additonal service air compressors appears to be behind

9. Valves:
    - This is a 'critical activity' for the project. The RCRB were unable to review the full scope of this work with all the owners but did not get a view that the potential impact was understood, nor was there clarity in how the scope is being managed. Project OPEX is that the valve program is the "Achilles heel" of most refurbishments and needs considerable oversight. The RCRB did not observed this.
    - The timelines for procurement of some valves under BOP scope will be close to the 'need-by date' for the work in the field. The project may want to consider looking at some forms of incentives to encourage contractors to perform at higher levels.

10. Good team dynamic in TG project:

    The preparation to execute the turbine generator work appears to be progressing well.

    - Personnel are comfortable with each other and the required work is being completed. Vertical slice meeting – good teamwork, not defensive, supporting each other, meeting the schedule. The vertical slice schedule reviews are viewed as a positive activity, and are effective at uncovering important issues that need to be addressed.
    - All project parts have arrived on time (including contingency parts). Preparatory work started (crane work) is being executed as scheduled and they are meeting their commitments.

11. RFR team dynamic:

    - The RCRB see progress in the level of readiness of the RFR project. The JV project team appears to be working well together with the OPG project, and the right behaviours are being exhibited. The JV team depends on other organizations for support (e.g. airlock repair) and its ability to minimize impacts on their critical path work will depend on the responsiveness of those organizations. The previously discussed interface and accountability issues can adversely impact critical path schedule if not resolved. The RCRB will continue to monitor the progress being made.

12. Material Staging:

    - The project "material staging" facility was toured, and found to be world class and one of the best organized and best laid out facilities that the RCRB has seen. In addition, the facility is being run and owned by a dedicated individual.

DARLINGTON REFURBISHMENT PROGRAM
OVERVIEW

1.0 PROGRAM SUMMARY

The Darlington Refurbishment Program (the "Program" or "DRP") is a multi-year, multi-phase mega-project that will enable the Darlington Generating Station ("Darlington") to continue safe and reliable operation until approximately 2055. The Program includes the replacement of life-limiting critical components, the completion of upgrades to meet applicable regulatory requirements, and the rehabilitation of components at Darlington's four units. The Program is comprised of individual projects of various scales and sizes that will be executed during multi-year outages.

In this application, OPG provides an update on the progress of the DRP and evidence to support its request for approval of in-service additions through 2021, including the in-service additions related to Unit 2 refurbishment. More specifically, OPG's pre-filed evidence demonstrates that:

- OPG has successfully performed the detailed planning that is necessary to determine Program scope and to establish high-confidence schedule ("schedule") and cost estimates for safely completing the Unit 2 refurbishment by February 2020 and refurbishment of the other three units thereafter; and
- OPG has in place the resources, organization and processes necessary to execute the refurbishment of Unit 2, and the Program in its entirety, safely, on time, on budget, and to the required quality level.

As part of the work completed during the Definition Phase of the Program, all major contracts required to execute the scope of the DRP have been awarded. The detailed planning conducted by OPG and its contractors during the Definition Phase has enabled the development of a four-unit budget and schedule for the successful execution of the DRP. Critical to OPG's planning efforts during this phase have been the construction of a full scale reactor mock-up and other training facilities which have been brought into service in this phase, as well as the Retube and Feeder Replacement tooling development and testing in

the mock-up. Equally important has been the completion of the Unit 2 detailed engineering for each design modification package for all committed scope that is part of the DRP. Based upon this work, OPG prepared a detailed four-unit budget and schedule (the "Release Quality Estimate" or "RQE"), which was finalized in November 2015 (as discussed in Ex. D2-2-8).

Refurbishment of all four Darlington units will take place over a total span of 112 months (October 2016 to February 2026), including 40 months for Unit 2 from October 2016 to February 2020. Based on the significant effort that went into developing the RQE, which was approved by OPG's Board of Directors on November 13, 2015, OPG has a high level of confidence in the DRP cost estimate of $12.8B, which includes contingency, capitalized interest and escalation. The RQE establishes a four-unit, program-level control budget that serves as the baseline against which the success of the DRP will be measured. Subsequent to receiving approval from OPG's Board of Directors, the RQE was provided to the Minister of Energy, who announced the Province's endorsement of the DRP on January 11, 2016.[1]

A simplified breakdown showing the Program components included in RQE and their budget is provided in Chart 1, below, followed by brief descriptions of the listed components. Life to date expenditures (to the end of 2015) are $2.2B, inclusive of interest and escalation.

[1] See: https://news.ontario.ca/mei/en/2016/01/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html.

Chart 1

Simplified Breakdown of Total DRP Release Quality Estimate[2]

Program Component	RQE Total Cost (Billion $)	RQE Total Cost (%)
Major Work Bundles	5.54	43
Safety Improvement Opportunities	0.20	2
Facilities & Infrastructure Projects	0.64	5
OPG Functional Support	2.23	17
Early Release Funds	0.11	1
Contingency	1.71	13
Interest & Escalation	2.37	19
Total Cost Estimate	**12.8**	**100**

Major Work Bundles are logical groupings of work scope, each consisting of a number of individual projects, defined by OPG for purposes of effectively contracting work to outside contractors and assigning project management accountabilities. The work to be undertaken through the major work bundles consists of the replacement and rehabilitation of components, inspections and the completion of upgrades directly related to unit refurbishment. The major work bundles are (1) Retube and Feeder Replacement ("RFR"), (2) Turbines, Generators and Auxiliaries ("Turbine Generator"), (3) Fuel Handling and Defueling, (4) Steam Generators, and (5) Balance of Plant.

Safety Improvement Opportunities ("SIO") are initiatives which OPG committed to in the Environmental Assessment ("EA") for the DRP, primarily to address beyond-design basis or four-unit events. The need for this work was established through the EA, which was filed with the Canadian Nuclear Safety Commission ("CNSC"). To meet required in-service dates, OPG commenced execution of SIO work early in the Definition Phase of the Program. The SIO are useful to OPG's current and future nuclear operations independent of whether the DRP is completed.

[2] The vast majority of these amounts are capital, but included in these amounts are some amounts (e.g. removal costs) that are expensed as OM&A. OM&A costs associated with the DRP are set out in Ex. F2-7-1.

Facilities and Infrastructure Projects ("F&IP") are projects that do not involve the refurbishment of units but which are necessary to enable execution of the unit refurbishments. A number of the F&IP involve upgrades to Darlington site infrastructure to ensure it can effectively support continued operations for 30 or more years. Other F&IP involve facilities that are needed to support DRP activities during the life of the Program. To meet required in-service dates, OPG commenced the F&IP work early in the Definition Phase of the Program. The F&IP are expected to remain useful to OPG's current and future nuclear operations independent of whether the DRP is completed.

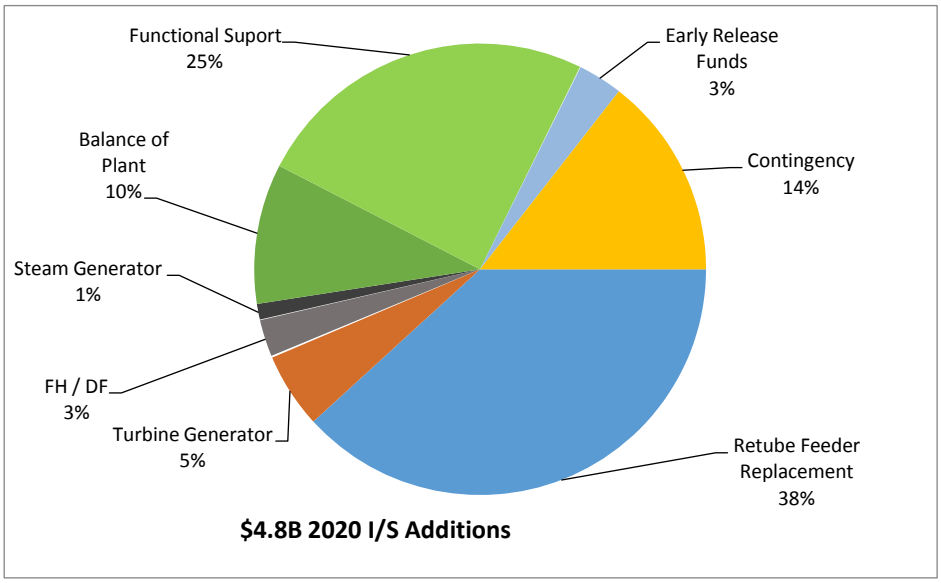
OPG Functional Support refers to work carried out by groups (referred to as "Functions") within OPG's DRP organization. The Functions provide a broad range of support that is critical for the success of the major work bundles and the Program as a whole, including oversight, coordination and integration among the various contractors and ongoing station operations. The largest of the groups, the Operations and Maintenance Function, is distinct from the others because it is both a functional and execution organization in that it provides functional support to the major work bundles and also directly carries out work at the station, particularly for the purpose of ensuring that refurbishment activities do not adversely impact Darlington's other operating units. It is largely through the Functions that OPG performs its vital role as the Program owner, with overall responsibility for Program management, deliverables, costs and schedule, as well as full integration with the operating units in order to comply with all CNSC regulations and safe work practices, including permits and work control, radiation protection, chemistry and environmental controls.

The remaining Program components consist of: (i) *Early Release Funds*, which are costs incurred during the Preliminary Planning Phase, such as with respect to EA and CNSC approvals work, that cannot be attributed to particular major work bundles or Functions; (ii) *Contingency*, which is an element of the cost estimate that is allocated to manage uncertainty and risk throughout the life of the Program, and which is expected to be spent based on OPG's in-depth assessment of the DRP risks and uncertainties that cannot be avoided or fully mitigated; and (iii) *Interest and Escalation*, which are included in the RQE to reflect costs associated with the passage of time during the life of the Program.

As noted above, the total four-unit budget to refurbish the four Darlington units is $12.8B. Within the 2017-2021 period, all of the F&IP and SIO will be placed in service and the Unit 2 refurbishment will be completed and placed in service. For the purpose of OPG's request for approval of in-service additions, $4,800.2M is forecast to come into service in 2020 for the Unit 2 refurbishment. A simplified breakdown showing the components of the Unit 2 amount is provided in Figure 1, below. While actual costs for particular components shown in Figure 1 may ultimately be higher or lower than forecast, OPG will complete the Unit 2 refurbishment within the total envelope budgeted for Unit 2 and OPG's performance with respect to cost should be considered on this basis.

Figure 1

Simplified Breakdown of Unit 2 In-Service Amounts[3]



OPG plans to issue annual status reports to the public for the duration of the Program. This reporting will include a range of measures, including construction completion, cost performance, schedule performance and safety performance, and is described in greater detail in section 7 of Ex. D2-2-9.

[3] Interest and escalation for in-service amounts are included in major work bundle costs.

2.0 APPROVALS SOUGHT

In the current application, OPG seeks the following OEB approvals for the DRP:

- In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the test period, $374.4M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021 on a forecast basis. These amounts reflect the addition to rate base of $4,800.2M related to Unit 2 in-service addition in 2020 and 2021, as well as $743.1M related to Unit Refurbishment Early In-Service Projects[4], Safety Improvement Opportunities, and Facilities & Infrastructure Projects. If actual additions to rate base are different from forecast amounts, the cost impact of the difference will be recorded in the Capacity Refurbishment Variance Account ("CRVA") and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding; and
- OM&A expenditures of $41.5M in 2017, $13.8M in 2018, $3.5M in 2019, $48.4M in 2020, and $19.7M in 2021 (Ex. F2-7-1).

OPG also seeks recovery of the contribution of the DRP to the Capacity Refurbishment Variance Account ("CRVA") 2015 balance, as discussed in Ex. H1-1-1.

3.0 EVIDENCE ROADMAP

To understand the rationale underlying the evidence roadmap set out below, it is important to understand that OPG has approached the DRP in a manner that is consistent with generally accepted methods for planning and implementing mega-projects. This process of planning and implementing the DRP provides the broad framework for presentation of this evidence.

More particularly, given the Program's complexity and in order to successfully complete the DRP on time and on budget, OPG must have in place a number of elements that are essential for Program development, execution and completion. This includes appropriate structure, both with respect to OPG's contractual relationships as well as organizationally, to ensure the appropriate allocation of risk and cost responsibility and an effective and

[4] See section 2.2 of Ex. D2-2-10 for more information on Unit Refurbishment Early In-Service Projects.

functioning working relationship between OPG as Program owner and its contractors. Moreover, OPG must undertake rigorous planning to ensure proper scope and corresponding cost and schedule. However, this is not an end in itself. OPG must also require its contractors to execute the major work bundles in an efficient and cost effective manner and must conduct itself likewise in its capacity as owner. Furthermore, while executing the four-unit refurbishment, OPG must comply with all CNSC regulatory requirements. OPG must also comply with provincial requirements for nuclear refurbishment as set out in the Long Term Energy Plan ("LTEP").

The Program cannot be viewed through a single lens or by considering a single component. As a result, OPG's evidence is structured so as to enable the OEB to understand that OPG (i) has adopted the most appropriate contracting strategy; (ii) has established an effective organization that aligns with and supports that strategy; (iii) has through that organization and in conjunction with its contractors undertaken extensive planning to define the scope, plan the schedule and estimate the cost of the Program; and (iv) has an effective execution strategy to ensure safe completion of the Program on time and on budget. The evidence is organized as follows:

- Ex. D2-2-1 (Program Overview) provides a summary of the Program, the approvals sought, this evidence roadmap and a description of the relevant regulatory framework, including recent amendments to Ontario Regulation 53/05, the Province's Long-Term Energy Plan and the relevant requirements of the CNSC;
- Ex. D2-2-2 (Program Structure) describes OPG's overall commercial strategy for the DRP, which establishes OPG as the Program owner and defines OPG's relationships with its external contractors. In a project of the magnitude of the DRP, it is critical that the responsibilities and accountabilities for project risks and execution be clear. It is also important to ensure alignment between the commercial/contracting strategies and the owner's organizational structure. This schedule describes how OPG has structured itself as the Program owner as well as the management system structures used by OPG to exercise its role as owner;
- Ex. D2-2-3 (Major Work Bundle Structure and Contracts) describes how OPG has structured the major work bundles, as well as the contracting approaches that OPG

has used for each of the major work bundles and the SIO and F&IP projects. The contracting models employed by OPG and the specific contract terms, such as with respect to pricing, will play a significant role in determining how the work will be performed and the overall success of the Program;

- Ex. D2-2-4 to Ex. D2-2-8 (Program Planning, Program Scope, Program Schedule, Contingency, and Cost) are all related directly to the development and approval of the RQE. Program planning concerns the significant investment in planning made by OPG during the Definition Phase to establish detailed scope, schedule and cost estimates, thereby minimizing the risk of scope creep, schedule delays and resulting increases in cost. OPG's approaches to identifying, defining and developing the Program scope, schedules, contingency amounts and cost estimates are considered in greater detail in these schedules;
- Ex. D2-2-9 (Program Execution) focuses on how OPG will manage the Program during execution, including the methods by which OPG as Program owner will manage circumstances that affect scope, schedule, cost and quality during refurbishment execution. In particular, this schedule considers the key activities to be carried out by certain OPG functional support groups during execution, as well as other key controlling activities all of which will enable OPG to effectively track progress and manage execution risk; and
- Ex. D2-2-10 (In-Service Amounts) describes the capital in-service additions, including for Unit 2 refurbishment, unit refurbishment early in-service projects, SIO and F&IP projects, as well as applicable variance analysis.

A detailed breakdown of the DRP evidence structure is included in Attachment 1.

OPG has also engaged independent experts to review and verify key aspects of the Program. The following independent expert reviews are provided in support of the evidence:

- KPMG review of risk management and contingency development process (Ex. D2-2-7, Attachment 1);
- KPMG review of the governance and processes to develop the RQE (Ex. D2-2-8, Attachment 2);

- Modus Strategic Solutions Canada Company and Burns & McDonnell Canada Ltd. Review of the RQE development process (Ex. D2-2-8, Attachment 3); and
- an expert panel, comprised of four individuals with retube and feeder replacement experience, review of the cost estimate for retube and feeder replacement (Ex. D2-2-8, Attachment 4).

In addition, two independent experts have been engaged to give evidence as follows:

- Concentric Energy Advisors, Inc. to provide an independent, updated assessment of their report filed in EB-2013-0321 of the commercial strategies developed for the RFR work package (Ex. D2-2-11, Attachment 1); and
- Pegasus Global Holdings, Inc. to provide an independent and objective assessment of the degree to which OPG's plan and approach to execution of the Program are consistent with the way other megaprojects and mega programs of comparable magnitude, scale and complexity have been carried out (Ex. D2-2-11, Attachment 3).

4.0 REGULATORY FRAMEWORK

4.1 Amendments to O. Reg. 53/05

On January 1, 2016, Ontario Regulation 53/05, *Payments Under Section 78.1 of the Ontario Energy Board Act* (O. Reg. 53/05) was amended to include additional provisions that deal with nuclear refurbishment costs and to define the scope of the OEB's jurisdiction in considering this application. In relation to the DRP, the amendments concern the following key aspects:

- The need for the DRP has been established by the regulation. As set out in the regulation, in setting nuclear payment amounts during the period from January 1, 2017 to the end of the DRP, the OEB shall accept the need for the DRP in light of the Ministry of Energy's 2013 LTEP and the related policy of the Minister endorsing the need for nuclear refurbishment.[5]

[5] O. Reg. 53/05, s. 6(2), para. 12(v).

- If the OEB is satisfied that costs of the DRP were prudently incurred and financial commitments were prudently made, the OEB must ensure that OPG recovers its capital and non-capital costs and firm financial commitments incurred for the DRP.[6]
- The OEB must permit OPG to establish a rate smoothing deferral account for the DRP.[7]
- In setting payment amounts for the deferral period (i.e. from January 1, 2017 to the end of the DRP), the OEB must determine, on a five year basis for the first ten years of the deferral period, and thereafter on such periodic basis as the OEB determines, the portion of the approved nuclear revenue requirement for each year that is to be deferred for purposes of making more stable the year-over-year changes in the nuclear payment amount.[8] OPG's rate smoothing proposal is discussed in Ex. A1-3-3.

4.2 Long Term Energy Plan

As stated by the Minister of Energy in Ontario's LTEP: "[t]he government is committed to nuclear power. It will continue to be the backbone of our electricity system, supplying about half of Ontario's electricity generation."[9] The Minister further stated in the LTEP:

> The government will ensure a reliable supply of electricity by proceeding with the refurbishment of the province's existing nuclear fleet taking into account future demand levels. Refurbishment received strong, province-wide support during the 2013 LTEP consultation process. The merits of refurbishment are clear:
>
> - Refurbished nuclear is the most cost-effective generation available to Ontario for meeting base load requirements.
> - Existing nuclear generating stations are located in supportive communities, and have access to high-voltage transmission.
> - Nuclear generation produces no greenhouse gas emissions.[10]

[6] O. Reg. 53/05, s. 6(2), para. 4.
[7] O. Reg. 53/05, s. 5.5.
[8] O. Reg. 53/05, s. 6(2), paras. 12(i) and (ii).
[9] Government of Ontario, *Achieving Balance – Ontario's Long Term Energy Plan*, December 2013, p. 30.
[10] LTEP, page 29.

The LTEP sets out a number of principles with respect to the nuclear refurbishment process.[11] As highlighted in Attachment 2 below, OPG's plans for the DRP include a number of specific elements that align with each of these principles, which are as follows:

- minimize the commercial risk on the part of ratepayers and government;
- mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
- entrench appropriate and realistic off-ramps and scoping;
- require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
- make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
- take smaller initial steps to ensure there is opportunity to incorporate lessons learned from the refurbishment including collaboration by operators.

4.3 Minister's Support for DRP

In addition to issuing clear policy statements regarding the need for nuclear refurbishment, the Government of Ontario's support for the DRP has been affirmed through the Minister's announcement on January 11, 2016[12] endorsing OPG's plan to refurbish the four Darlington units.

4.4 CNSC Regulatory Framework

The CNSC exercises ongoing regulatory and licensing oversight over nuclear power plants in Canada. Continued operation of Darlington is largely dependent on the work that is required for long term safe operation.

The CNSC's regulatory expectations for proposed refurbishment and life extension projects at the time that OPG began to undertake the DRP required that OPG systematically identify and address all environmental and safety concerns, carry out an Integrated Safety Review

[11] LTEP, page 29.
[12] See footnote 1.

("ISR") and integrate them into a Global Assessment Report ("GAR") and an Integrated Implementation Plan ("IIP") in accordance with all CNSC regulations, including the requirements from Regulatory Document RD-360 (Life Extension of Nuclear Power Plants).[13] In December 2015, the CNSC ruled that OPG has completed an ISR, GAR and IIP as set out in Regulatory Document RD-360. Regulatory Document REGDOC-2.3.3 (Periodic Safety Reviews) has superseded Regulatory Document RD-360 relating to the life extension of nuclear plants. As part of Darlington's renewed Nuclear Power Reactor Operating Licence (discussed further below), in accordance with REGDOC-2.3.3 (Periodic Safety Reviews), the CNSC ruled that OPG must conduct a periodic safety review in support of OPG's next Nuclear Power Reactor Operating Licence application to confirm that the facility remains consistent with a set of modern codes and standards to demonstrate that the safety basis remains valid. CNSC's Regulatory Document REGDOC-2.3.3: Periodic Safety Reviews can found in Attachment 3, and Regulatory Document RD-360: Life Extension of Nuclear Power Plants can be found in Attachment 4. In addition, OPG is required to adhere to the requirements of the *Nuclear Safety and Control Act*, the *Canadian Environmental Assessment Act*, all associated regulations, and conditions under its operating license for Darlington.

The EA Screening Report for the DRP was submitted to the CNSC on December 1, 2011. The CNSC released its decision regarding the EA on March 14, 2013. The overall finding of the CNSC was that the DRP will not result in any significant adverse environmental effects given the proposed mitigation measures. As required by the OEB's Decision in EB-2013-0321, OPG is filing as part of this application updates of actual costs of the EA follow-up studies. These updates are provided in Attachment 5.

[13] As set out in Regulatory Document RD-360, for a nuclear life extension project, the CNSC expects the licensee to demonstrate that the following objectives are met:

- The technical scope of the project is adequately determined through an IIP that takes into account the results of an EA and an ISR;
- Programs and processes that take into account the special considerations of the project are established; and
- The project is appropriately planned and executed.

(See: CNSC, RD-360: Life Extension of Nuclear Power Plants, Section 4.0.)

On December 23, 2015, the CNSC issued a renewed Darlington Nuclear Power Reactor Operating Licence effective January 1, 2016 until November 30, 2025. OPG's Nuclear Power Reactor Operating Licence application included the proposed refurbishment of Darlington. The CNSC concluded that OPG is qualified to carry on the proposed refurbishment project. The CNSC's Record of Proceedings, Including Reasons for Decisions was issued on March 2, 2016.[14]

[14] The CNSC Reasons for Decision can be found on the CNSC website as e-Doc 4920689 at: http://www.nuclearsafety.gc.ca/eng/the-commission/pdf/2015-11-02-CompleteDecision-OPG-Darlington-e-edoc4920689.pdf.

ATTACHMENTS

Attachment 1:	Detailed Breakdown of Evidence Structure
Attachment 2:	OPG Actions Taken/Planned in Alignment with LTEP Principles
Attachment 3:	Regulatory Document REGDOC-2.3.3: Periodic Safety Reviews
Attachment 4:	Regulatory Document RD-360: Life Extension of Nuclear Power Plants
Attachment 5:	Costs of Environmental Assessment Follow-up Studies

SECOND IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes that have occurred since OPG filed the first Impact Statement (Ex. N1-1-1) on December 20, 2016, consistent with the requirements of paragraph 11.02 of the OEB's *Rules of Practice and Procedure*. These changes impact the revenue requirement for the nuclear facilities and result from the need to exclude forecast capital in-service amounts for the Heavy Water Storage and Drum Handling Facility Project ("D2O Project") relating to the Darlington Refurbishment Program ("DRP") from the scope of OPG's Application.

2.0 SUMMARY

This update to the Application is required to reflect material changes in costs for the nuclear facilities in the 2017 to 2021 incentive rate-setting ("IR") period. These changes are driven by the fact that OPG is no longer seeking OEB approval of the forecast capital in-service amounts for the D2O Project, which was described in the pre-filed evidence as one of the Facilities & Infrastructure Projects ("F&IP") for the DRP (Ex. D2-2-10, s. 2.4; Tables 1, 2, 4 and 5; and Attachment 1, Tab 1).

The purpose of the D2O Project is to provide a heavy water storage and processing facility for the removal of heavy water from the Darlington units during refurbishment as well as a long-term solution for the management of heavy water during normal operations. In light of the tremendous complexity and scale associated with this first of its kind facility, certain circumstances relating to the detailed engineering design of the D2O Project have recently arisen that are expected to impact the forecast in-service date and may impact the in-service amounts for the project. OPG is actively reviewing the engineering design, including retaining third party expert advisors to assist in this regard.

Given the present uncertainty associated with the D2O Project, OPG is amending its evidence in this proceeding to exclude the capital in-service amounts for the D2O Project

forecast to occur during the 2017 to 2021 period, and to revise the revenue requirement accordingly. The actual revenue requirement impact of the D2O Project will be recorded in the nuclear portion of the Capacity Refurbishment Variance Account ("CRVA") once the project enters into productive service. Such entries into the CRVA will continue to be recorded until the OEB-approved D2O Project in-service amount is reflected in the revenue requirement through a subsequent rate setting process. The OEB will have the opportunity to conduct a prudence review in respect of the D2O Project after it has been completed and placed into service. This approach is consistent with the OEB's Decision with Reasons in EB-2013-0321[1]. The prudence review of the D2O Project is expected to occur at the mid-term review in the first half of 2019. The in-service amount determined by the OEB as a result of that review will provide the basis for determining the revenue requirement impacts that will be recorded in the CRVA until the OEB approved unamortized in-service D2O Project amount is reflected in revenue requirements in a subsequent rate setting process.

3.0 ITEMS INCLUDED IN THE IMPACT STATEMENT

This section provides additional detail on the changes reflected in the revised revenue requirement requested for the IR period.

The impact on the nuclear revenue requirement from removing the projected in-service amounts for the D2O Project is $(40.4)M in 2017, $(36.9)M in 2018, $(36.4)M in 2019, $(40.9)M in 2020 and $(40.1)M in 2021, as shown in Chart 1 below.

[1] EB-2013-0321 Decision with Reasons, page 59.

Chart 1

Nuclear Revenue Requirement Impact of Removing Forecast D2O Project In-Service Amounts

Line No.		2017	2018	2019	2020	2021	Total
1	Net Plant Rate Base Decrease[1]	(240.5)	(353.7)	(343.0)	(332.4)	(321.7)	
2	Weighted Average Cost of Capital[2]	6.80%	6.66%	6.63%	6.61%	6.60%	
3	Decrease in Cost of Capital Amount (line 1 x line 2)	(16.4)	(23.6)	(22.7)	(22.0)	(21.2)	(105.9)
4	Decrease in Depreciation Expense	(6.9)	(10.7)	(10.7)	(10.7)	(10.7)	(49.6)
5	Decrease in Regulatory Income Taxes Before Loss Carryback[3]	(5.7)	(8.6)	(8.5)	(8.3)	(8.2)	(39.3)
6	Regulatory Tax Loss Carryback	(11.5)	6.0	5.5	-	-	0.0
7	**Total Revenue Requirement Change** (lines 3 through 6)	(40.4)	(36.9)	(36.4)	(40.9)	(40.1)	(194.7)

[1] From Chart 2, line 9

[2] As shown in Ex. N1-1-1 Table 2a, Note 1, col. (e)

[3] Calculated as: (line 1 x 49% proposed equity thickness x 8.78% ROE value + line 4) x 25% / (1-25%)

The updated nuclear revenue requirement is provided in Ex. N2-1-1 Table 1. The revised calculation of forecast nuclear regulatory income taxes for each year of the IR period is provided in Ex. N2-1-1 Table 2 and 2a, in the same format as Ex. N1-1-1 Tables 8 and 8a and Ex. F4-2-1 Tables 3a and 3b.

As shown in Ex. N2-1-1 Table 2, line 20, OPG projects nuclear regulatory tax losses in 2018 and 2019 and regulatory taxable income in 2017, 2020 and 2021, whereas the forecast in the first Impact Statement showed nuclear regulatory taxable income for all years of the IR period (Ex. N1-1-1 Table 8, line 20). The losses now projected in 2018 and 2019 are carried back to reduce nuclear regulatory taxable income for 2017. These tax loss carry backs impact regulatory income taxes in each of 2017, 2018 and2019, but not in total over the IR period, as shown in Chart 1, line 6.

The revised in-service amounts for DRP are provided in Table 3. Further details of the impact on proposed nuclear net plant rate base amounts of removing forecast in-service amounts for the D2O Project are provided in Charts 2 and 3 below.

Chart 2

Impact of Forecast D2O Project In-Service Amounts on Net Plant Rate Base

Line No.		Reference	2017	2018	2019	2020	2021
1	Gross Plant In-service - Opening Balance		-	365.9	365.9	365.9	365.9
2	Gross Plant In-service - Additions	Ex. D2-2-10, Table 2, line 3	365.9	-	-	-	-
3	Gross Plant In-service - Closing Balance	line 1 + line 2	365.9	365.9	365.9	365.9	365.9
4	Accumulated Depreciation - Opening Balance		-	6.9	17.5	28.2	38.9
5	Depreciation Expense	Chart 1, line 4	6.9	10.7	10.7	10.7	10.7
6	Accumulated Depreciation - Closing Balance	line 4 + line 5	6.9	17.5	28.2	38.9	49.6
7	Net Plant In-service - Opening Balance	line 1 + line 4	-	359.0	348.3	337.7	327.0
8	Net Plant In-service - Closing Balance	line 3 - line 6	359.0	348.3	337.7	327.0	316.3
9	**Net Plant Rate Base Impact**	Note 1	**240.5**	**353.7**	**343.0**	**332.3**	**321.7**

[1] As the forecast in-service addition is at the beginning of May 2017 (see Ex. B3-3-1 Table 2, Note 1), it is a assigned an 8/12 weighting for 2017, with net plant rate base amount calculated as 8/12 x line 2 - (line 4 - line 6)/2. For 2018-2021, net plant rate base amount is calculated as (line 7 + line 8)/2.

Chart 3

Changes in Nuclear Rate Base

Line No.		Reference	2017	2018	2019	2020	2021
	N1 Update:						
1	Darlington Refurbishment Program Net Plant Rate Base	Ex. B3-2-2 Table 1, lines 9 and 16	852.3	955.2	929.7	5,031.4	5,476.2
2	Total Nuclear Net Plant Rate Base	Ex. N1-1-1 Table 1, line 1	3,156.9	3,262.9	3,147.8	7,137.5	7,574.1
3	Total Nuclear Rate Base	Ex. N1-1-1 Table 1, line 4	3,868.4	3,960.6	3,819.3	7,786.2	8,208.6
	N2 Update:						
4	Darlington Refurbishment Program Net Plant Rate Base	line 1 less Chart 2, line 9	611.9	601.5	586.7	4,699.1	5,154.5
5	Total Nuclear Net Plant Rate Base	Ex. N2-1-1 Table 1, line 1	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
6	Total Nuclear Rate Base	Ex. N2-1-1 Table 1, line 4	3,627.9	3,606.9	3,476.2	7,453.8	7,887.0
7	**Nuclear Rate Base Decrease**		**(240.5)**	**(353.7)**	**(343.0)**	**(332.4)**	**(321.7)**

4.0 SUMMARY OF CHANGES IN APPROVALS SOUGHT

The items identified in this Impact Statement result in amendments to the following approvals sought by OPG in this Application for the IR period: (i) nuclear revenues requirements, (ii) nuclear rate base, (iii) portion of the nuclear revenue requirements deferred under rate

smoothing, and (iv) in-service additions to rate base for DRP for the IR period. The updated approvals are detailed below. In conjunction with this exhibit, OPG has filed an amended Ex. A1-2-2 Approvals and Ex. A1-3-4 Drivers of Deficiency to reflect these changes. A revised revenue requirement workform is provided in Attachment 1. OPG is not updating its request for smoothed nuclear payment amounts or riders, and therefore there is no change to the annualized residential consumer impact of OPG's Application.

Nuclear Revenue Requirement

1. The approval of the following revised revenue requirements for the nuclear facilities, net of the nuclear stretch factor, for each year of the IR period:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,161.4M
January 1, 2018 through December 31, 2018	$3,185.7M
January 1, 2019 through December 31, 2019	$3,273.2M
January 1, 2020 through December 31, 2020	$3,783.5M
January 1, 2021 through December 31, 2021	$3,397.8M

Nuclear Rate Base

2. The approval of the following revised rate base values for the nuclear facilities for each year of the IR period:

Year	Rate Base
2017	$3,627.9M
2018	$3,606.9M
2019	$3,476.2M
2020	$7,453.8M
2021	$7,887.0M

Deferred Nuclear Revenue Requirement

3. The approval of the deferred amounts resulting from the revised nuclear revenue requirements identified in item 1 above of $654M, $375M, $109M, $421M and $(137)M in 2017, 2018, 2019, 2020 and 2021, respectively, and as shown below:

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,161	$ 3,186	$ 3,273	$ 3,783	$ 3,398
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 654	$ 375	$ 109	$ 421	$ (137)

Darlington Refurbishment Program In-Service Amounts for IR Period

4. The approval of the revised in-service additions to rate base for the DRP of $8.5M in 2017, $8.9M in 2018, $4,809.2M in 2020 and $0.4M in 2021 on a forecast basis.

ATTACHMENTS

Attachment 1: Revenue Requirement Workform

Board Staff Interrogatory #55

Issue Number: 4.3

Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Ref: Exh D2-2-8, Attachment 1 page 2

The DRP BCS states that "[t]he current target date to start the Refurbishment outage on Unit 2 is October 2016, prior to which management will complete a Unit 2 Execution estimate and seek further authorization and funding approval from the Board."

a) Please provide an update on the current start date for Unit 2

b) On page 23 of Attachment 1 to Ex. D2-2-8, the overview identifies that funding release 5b is scheduled for mid-2016. Was the Unit 2 Execution estimate completed and approved by the Board (Release 5b)? If so, please provide a copy.

Response

a) The current start date for Unit 2 remains October 15, 2016.

b) The Unit 2 Execution Estimate was completed and approved by the Board of Directors in August 2016. Please see Attachment 1 (Attachment 1 is marked confidential but OPG has determined it is non-confidential in its entirety).

August 12, 2016

DARLINGTON REFURBISHMENT - UNIT 2 EXECUTION

DECISION REQUIRED

The purpose of this memo is to provide a summary of the Darlington Refurbishment Program (DRP) Unit 2 cost and schedule estimates and key risks, and request approval for:

- Commencement of Unit 2 refurbishment in October 2016;
- The Unit 2 budget and schedule; and
- Release of additional funds in the amount of $2,876 Million, which includes $635 Million of contingency to execute the Unit 2 refurbishment.

ISSUE

In November 2015, OPG's Board of Directors approved the Release Quality Estimate (RQE), representing the overall 4-unit high confidence budget, schedule and release strategy to refurbish the four Darlington units.

Since that time, as management continued with the detailed planning and preparations for execution of the Unit 2 refurbishment, management has further developed the Unit 2 cost estimate and schedule and performed an updated risk analyses. Consistent with the approved funding strategy, Management is now requesting Board approval to proceed with the refurbishment of Unit 2 starting in October 2016 and to release the required funding to complete the refurbishment of Unit 2.

ANALYSIS

The current Unit 2 Execution Estimate (U2EE) is an update to RQE, which takes into consideration additional planning and work executed over the past 8 months, and incorporates the following:

- Revised estimates for scope that has progressed from a Class V or IV estimate to a Class III and II.
- Updated base cost estimates to reflect the development of comprehensive execution work packages and an enhanced understanding of the cost to perform the work, which is a direct outcome of estimate development and actual field work.
- Updated risk profile, and resultant contingency required for residual risks.
- Assessment of the actual costs to date and the estimate-to-complete (ETC) for all work packages.
- Review of the cash flow, including interest and escalation requirements, against the current schedule.

All of these items have been compiled into the current U2EE, as well as a review of the 4-unit overall cost estimate. The following sections summarize this analysis.

1. Management is adequately prepared and ready to proceed with the execution of Unit 2.

Management has provided an update on the status of the DRP to the Darlington Refurbishment Committee (DRC) at its August 11, 2016 meeting. In the report, Management indicates that the DRP remains on track to commence the execution and refurbishment of Unit 2 in October 2016.

Management is executing all pre-requisite projects in order to be ready to commence the refurbishment of Unit 2. Some of these projects are currently behind schedule; however, all critical projects required to enable the start of refurbishment are expected to be complete prior to their need date.

Management is focused on applying lessons learned from the Ready to Execute (RTE) test period, where processes for managing in-plant execution of work were tested and refined, to increase the productivity and schedule compliance of all work being performed in the field. Although many of the pre-requisite projects are not required for the start of refurbishment, management remains focused on the delivery of these projects as quickly as reasonably feasible while managing safety, quality, and cost.

2. Unit 2 scope has been clearly specified, engineering is complete, and comprehensive work plans are in place.

Since RQE, there have been no major scope changes to the DRP.

Detailed design engineering is substantially complete for all field work to be executed during Unit 2.

Management has focused on the completion of Phase 1 Comprehensive Work Packages (CWPs) that describe the details of the work to be executed in the field. The CWPs for all the project bundles are now essentially complete with a few minor exceptions. Completion of the CWPs took an additional month beyond what was planned due primarily to station interfaces for the Re-tube & Feeder Replacement (RFR) project not being fully understood by the vendor; however, they have been completed with quality, and provide the necessary information to complete field execution of all project work.

3. Regulatory certainty has been achieved.

The Integrated Implementation Plan (IIP) identifies the regulatory scope required to be completed during the refurbishment period, including work being done by the station.

The 51 Integrated Implementation Plan (IIP) tasks that have been committed to the Canadian Nuclear Safety Commission (CNSC) for completion in 2016 are on track. To date, 17 items are complete and field work for an additional 10 is complete with document closeout underway.

OPG has received all remaining regulatory approvals from the CNSC required to support the start of Unit 2 refurbishment. No additional approvals are required to commence refurbishment of Unit 2.

OPG has committed in the IIP to have the 3rd Emergency Power Generator (EPG) and Containment Filtered Venting System (CFVS) in-service prior to the start of the Unit 2 refurbishment, and continues to demonstrate to the CNSC that completion of these projects is a high priority. The CNSC is being kept informed of the project complexities, including commissioning and site integration of the 3rd EPG, and is aware of the potential risk to the in-service date. In the event that the IIP commitment cannot be achieved, the IIP Change Control Process will be initiated.

The regulatory hold-points for returning the units to service, after refurbishment, have been agreed to with the CNSC. Development of a decision and escalation protocol with the CNSC, to ensure scope and schedule commitments are effectively managed, is being considered.

4. The Unit 2 high confidence schedule duration, consistent with RQE, remains at 40 months; the 4-unit schedule remains at 112 months.

The Unit 2 high confidence schedule duration of 40 months remains consistent with RQE.

The only significant change to the high confidence 4-unit schedule since RQE was the de-lapping of Unit 3 from Unit 2, to be consistent with the Province's Long Term Energy Plan (LTEP) requirement to complete Unit 2 prior to commencing any subsequent units.

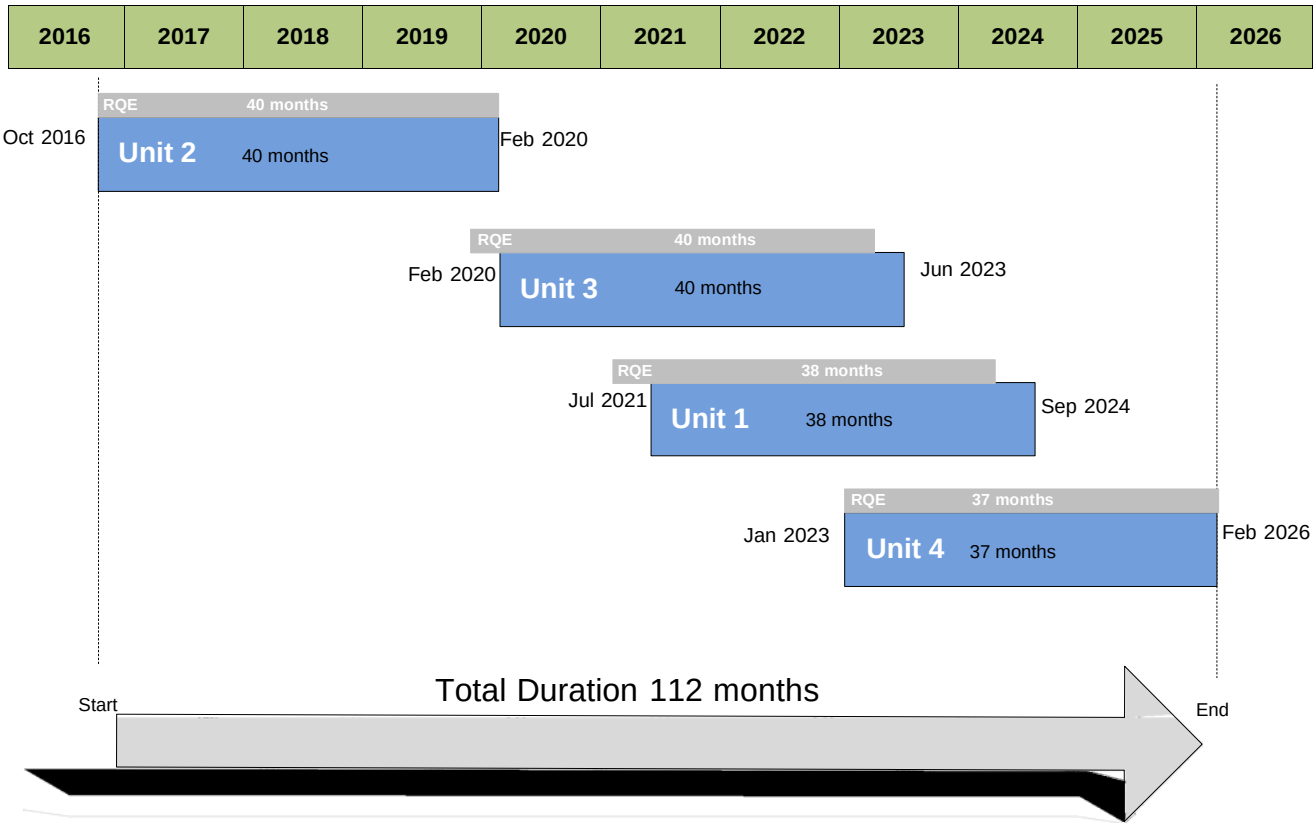
The overall 4-unit high confidence schedule duration remains at 112 months per Table 1 below:

Table 1: Comparison of 4-Unit High Confidence Schedule (RQE vs. U2EE)

Unit	High Confidence at RQE			High Confidence (U2EE)			Variance From RQE
	Start	Finish	Duration (Months)	Start	Finish	Duration (Months)	
Unit 2	15-Oct-16	15-Feb-20	40	15-Oct-16	15-Feb-20	40	0
Unit 3	15-Dec-19	15-Apr-23	40	15-Feb-20	15-June-23	40	0
Unit 1	15-Apr-21	15-Jun-24	38	15-Jul-21	15-Sep-24	38	0
Unit 4	15-Jan-23	15-Feb-26	37	15-Jan-23	15-Feb-26	37	0
4 Units	**15-Oct-16**	**15-Feb-26**	**112**	**15-Oct-16**	**15-Feb-26**	**112**	

The U2EE High Confidence schedule and comparison to RQE as noted above in Table 2, is illustrated in the following Figure A:

Figure A: Refurbishment 4-Unit High Confidence Project Schedule



High Confidence durations are shown above. Unit 2 project performance will however get managed against an aggressive planned outage duration (working schedule) of 35 months. Since RQE, detailed schedules have been further developed, and have resulted in a minor 10 day increase for activities within the removal and installation series. A copy of the Level 1 schedule is included as Appendix 1.

The planned outage duration is based on a detailed evaluation of the schedule risks for each segment of the critical path, including discrete technical risks such as a Primary Heat Transport pump motor failure during defueling and requirements for Primary Heat Transport system flush and Hot Conditioning on unit startup. Management is, and will continue to, look for opportunities to reduce schedule durations.

The high confidence schedule is the basis for the Release Quality Estimate, which is the program level control budget and this schedule is the schedule from which project success will be assessed. Management will report on the performance of the DRP to the DRC on a quarterly basis, against both the Unit 2 working schedule and the high confidence schedule, with clear indications of project status and contingency utilization.

Final detailed schedule reviews are now underway in order to ensure all potential interferences between vendors are eliminated and labour resources are effectively balanced. The final baseline Unit 2 working schedule will be issued in mid September. This schedule will contain over 75,000 tasks for OPG and the vendors.

5. A detailed review of Unit 2 execution phase risks and contingencies is now complete.

Management has finalized its review of schedule and cost risks. Since the RQE analysis in October, a reduction in cost estimating uncertainty contingency requirements has been observed, which reflects the progression of project estimates and the integration of lessons learned from the Ready to Execute test period.

As shown in Figure B, the percentage of project costs where the estimate is at Class III or better has increased since RQE from 94% to 98%. For those projects not yet at Class III, adequate contingency has been carried to reflect the remaining uncertainty with these projects.

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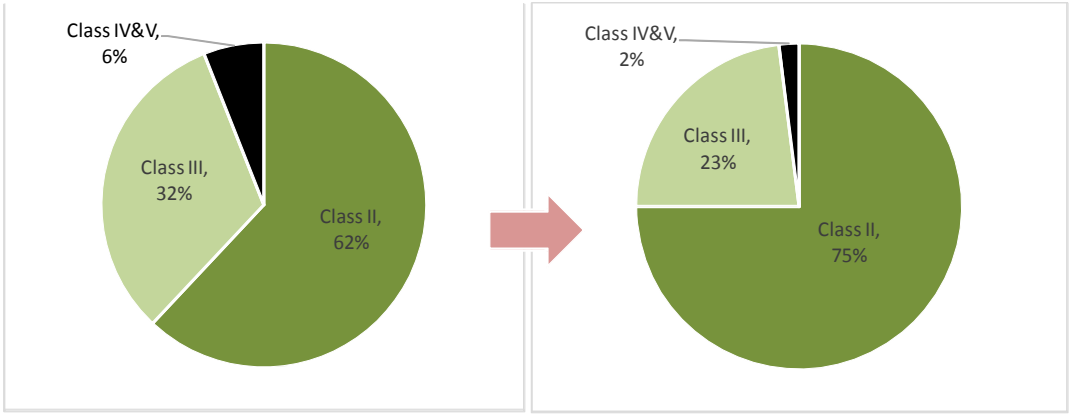
Figure B: Estimate Classification Summary



(1) Figures above represent 4-Unit estimates. Actions are already underway to finalize these estimates to Class III or II prior to work release and execution.

The contingency analysis summarized in Table 2 was derived through a detailed analysis and modeling of the current risk profile across the entire program. The assessed contingency is based on the residual risks contained within the DRP and excludes the $61 Million of contingency allocated since RQE. In addition to the continuous monitoring of contingency draw-downs, a thorough assessment of the risk profile and impact on contingency will be performed quarterly.

The outcome of Management's contingency analysis yielded that, at a high confidence, the estimate should include $2,006 Million of contingency for the DRP, including $677 Million for Unit 2.

There is no significant change to the anticipated contingency calculated at RQE. For clarity, RQE consisted of $1,706 Million of contingency in 2015 dollars, plus $300 Million of inflation and interest,

which totals $2,006 Million. Contingency on Unit 3 has increased due to a shift of risks from Unit 2 to Unit 3 related to the Turbine Controls installation on Unit 3.

Below, in Table 3, is a breakdown of the $2,006 Million of contingency, by unit and contingency type.

Table 2: 4-Unit Contingency Summary

Unit	RQE ($M)	Current U2EE ($M)	Changes since RQE ($M)
Campus Plan Program Total, *plus $41mil of add'l contingency included with projects	32	18	-14
Unit 2 Total	690	677	-13
Unit 3 Total	516	557	41
Unit 1 Total	419	409	-10
Unit 4 Total	350	345	-5
4-Unit Contingency ($M)	**2,006**	**2,006**	**0**

Table 3: 4-Unit Contingency Summary by Type

Level	Contingency Type	Updated 4-Unit Contingency ($M)	Facility and SIO Projects ($M)	U2 ($M)	U3 ($M)	U1 ($M)	U4 ($M)
PROJECT	**Project Discrete Risks** - Specific to Bundles	658	18	216	177	135	112
	Project Level Estimating Uncertainty - Project Bundles and Resources	192	-	67	54	38	33
	Critical Path Schedule Contingency - for the Working Schedule Duration	438	-	149	122	91	76
	Critical Path Schedule Contingency - to High Confidence Duration	192	-	66	55	38	33
PROGRAM	**Program Discrete Risks** - Functional Risks	458	-	153	129	95	81
	Program Level Estimating Uncertainty - Functional Resources	68	-	26	20	12	10
	Total Contingency $M	**2,006**	**18**	**677**	**557**	**409**	**345**

The contingency of $2,006 Million represents 23% of the Execution Phase Estimate-to-Complete cost of $8,300 Million, or 32% of the external vendors' estimate of $6,000 Million. With 98% of vendor cost estimates well defined at Class III or better, Management believes that the contingency amount is sufficient.

6. OPG's oversight requirement has been assessed and is deemed to be appropriately sized.

Since RQE, OPG's role as the General Contractor performing integration and oversight of safety, quality, schedule, cost and risk, with consideration of current field experience, has been evaluated.

Lessons learned from the pre-requisite projects have been evaluated and OPG has added resources in each of the following areas:

- Field construction support and oversight;
- Quality surveillance;
- Work control;
- Source surveillance and vendor procurement; and
- Contract and claims management.

Management is further evaluating its organization and looking for further opportunities to streamline processes and reduce oversight staff. Also, OPG's investment in vendor training, including supervisor training, is expected to improve performance and in time should have a positive impact on resources.

Due to the under spend in OPG labour of approximately $40 Million to date, management believes that these increases can be managed and will not impact the Unit 2 estimate. However, Management is also carrying $77 Million of contingency (per Unit) for risks and an uncertainty associated with higher owner's costs, which management believes is sufficient.

Management has put in place processes required to plan and forecast staff demands and will closely monitor all labour demands and variances during execution of the DRP to mitigate any further cost growth related to OPG's oversight.

The overall histograms of OPG and vendor resources are shown in Appendix 5A and 5B.

7. The Unit 2 high confidence cost estimate is $3.4 Billion including contingency, consistent with the estimate provided at RQE.

The high confidence cost estimate to execute Unit 2, including contingency is $3.4 Billion and is $24 Million higher than presented at RQE due several vendor changes, increase in OPG staffing, but offset by lower anticipated contingency needs.

Furthermore, the in-service amount of $4.8 Billion reported at RQE has been maintained.

Appendix 3 provides a project bundle level analysis of the current cost estimate and as compared to RQE.

8. The overall budget remains within the $12.8 Billion set at RQE.

As shown in Appendix 2, the overall 4-Unit high confidence cost estimate remains at $12.8 Billion.

Table 4: Refurbishment Current Estimate Compared to Prior Estimates

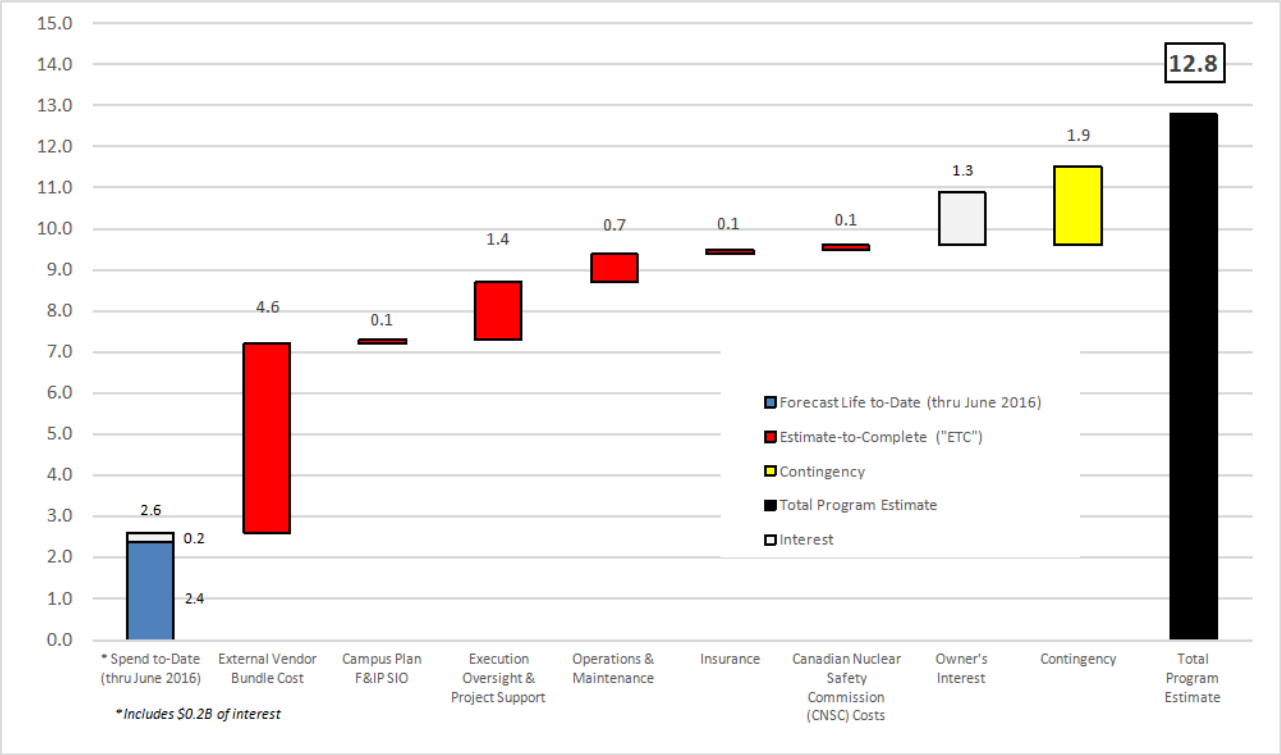
2009 Estimate	2015 RQE High Confidence Estimate	Current High Confidence Estimate
$14.0 Billion(1,2)	$12.8 Billion(2)	**$12.8 Billion(2)**

(1) The 2009 estimate was reported as $10 Billion in $2009, excluding interest and inflation. When interest and inflation is included, the estimate was $14 Billion.

(2) Estimate includes interest and inflation. Inflation is estimated at 2% and interest is estimated using 5% to 2021 and 6% thereafter.

Figure C below provides a summary of the cost elements that build up to the high confidence 4-unit cost estimate. Each cost element now includes allocated inflation.

Figure C: 4-Unit Cost Estimate Build-up



Appendix 2A and 2B provides a more detailed breakdown of the overall cost.

9. Funding is requested in the amount of $2.9 Billion to complete Unit 2 refurbishment.

The cumulative release at RQE was $3,228 Million including $723 Million for Unit 2 activities. The current high confidence cost estimate for the Unit 2 refurbishment, including $677 Million of contingency, is $3,417 Million. Management is requesting incremental funding of $2,876 Million to complete the refurbishment of Unit 2 as well as the Facility & Infrastructure, Safety Improvement, and other in-plant pre-requisite projects, for a total cumulative release of $6,104 Million. Details of the release amount are included in Appendix 6.

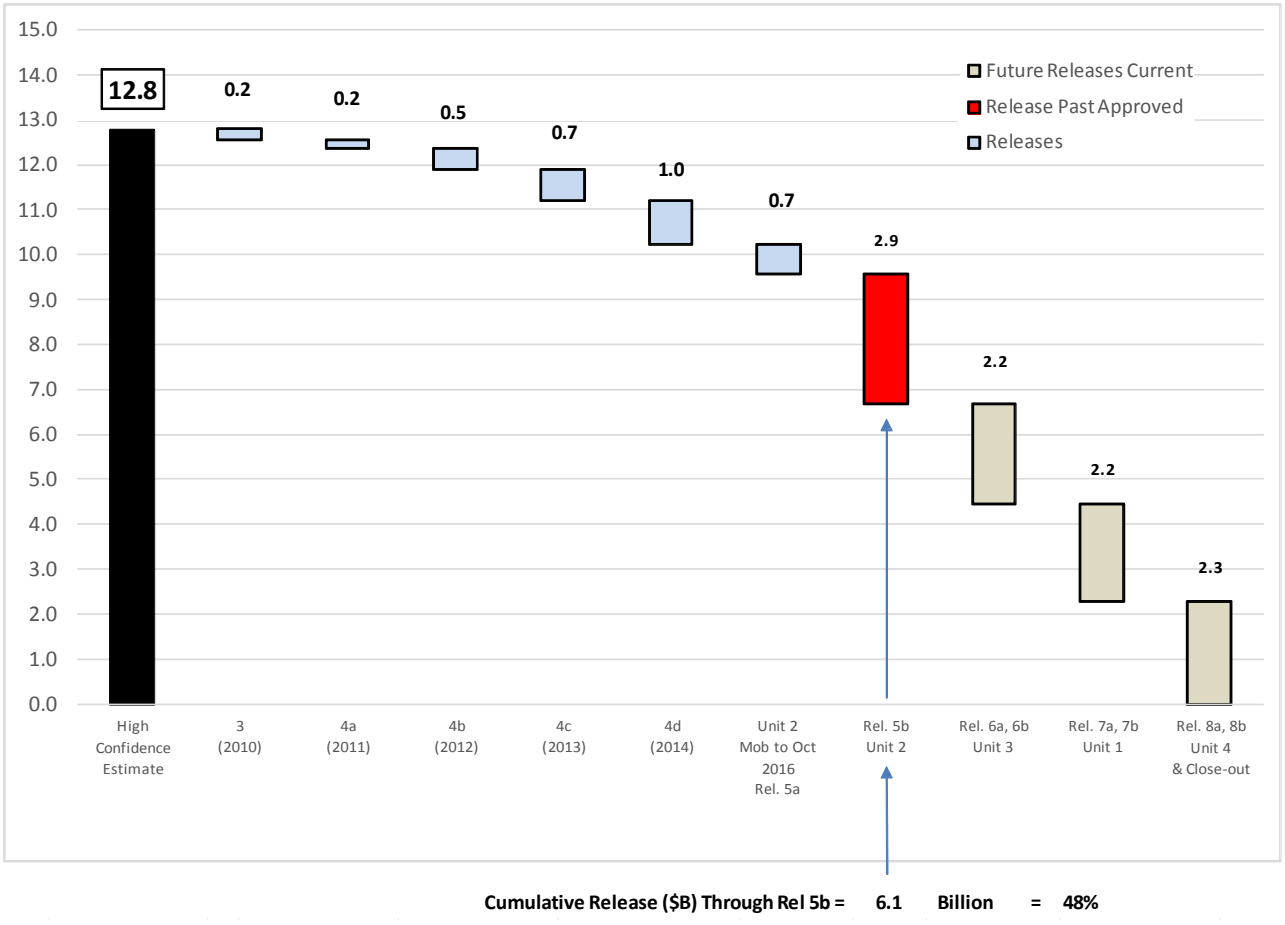
Table 5: Program Funding Releases

Previous Approved Funding Cumulative through Release 5a (at RQE)	Current Funding Request, Release 5b for U2 Execution	Cumulative Funding through end of Unit 2
3,228	2,876	6,104
Values in $Million		

Release 5a funding, approved by the Board in November 2015, included approximately $102 Million for a portion of subsequent unit planning, primarily for long lead materials for the Turbine Generator Control system, which will be installed initially on Unit 3, and the Re-tube and Feeder Replacement project.

Figure D below provides a summary of the cumulative releases to the DRP to date.

Figure D: Program Funding Releases



In 2017, Management will request additional funding to commence preliminary planning for subsequent unit refurbishments. This will include funding to complete engineering and to initiate long lead procurement for Unit 3. A dedicated team will be put in place to lead the Unit 3 planning effort.

10. The LUEC of refurbishing and continuing to operate the Darlington units for a further 30 years remains at 8.1 ¢/kWh (2015$).

There is no anticipated change to the economic assessment, and the LUEC of refurbishing and continuing to operate the Darlington station for a further 30 years remains at 8.1 ¢/kWh (2015$).

The DRP continues to contribute 3.3 ¢/kWh ($2015) to the LUEC estimate, and the post-refurbishment operations and support costs necessary to run the plant, including fuel, continue to contribute 4.8 ¢/kWh ($2015) to the total LUEC.

11. Management will commence reporting to the DRC on the status of the Unit 2 Execution Phase in November 2016.

The Unit 2 refurbishment baseline working schedule will be issued in mid September. At that time, Management will make any needed adjustments to the Unit 2 cost flows and control budget, which will then be used for performance monitoring and reporting.

RECOMMENDATION / RESOLUTION

Management is requesting that the Board of Directors approve the following items related to the DRP:

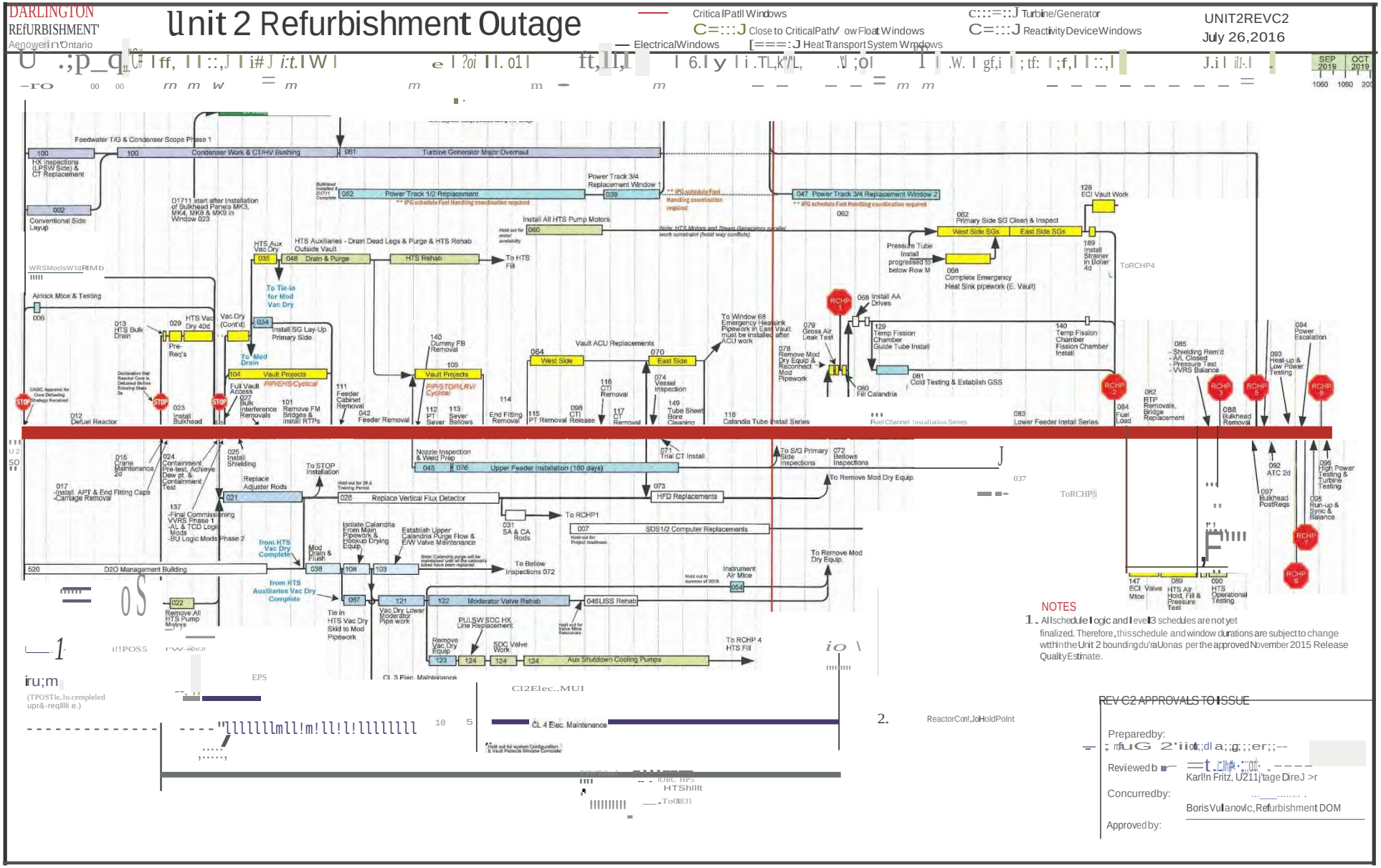
- Approval to commence Unit 2 refurbishment in October 2016;
- Approval of the Unit 2 high confidence cost estimate ($3.417 Billion) and high confidence schedule (40 months); and
- Approval of a release of funds in the amount of $2,876 Million, which includes $635 Million of contingency to execute the Unit 2 refurbishment.

Recommended by:	**Approved for submission to the Board of Directors by:**
_____	_____
Dietmar Reiner	Jeff Lyash
Senior Vice President, Nuclear Projects	President and CEO

This Board memo was reviewed and approved for submission to the Board of Directors by the Darlington Refurbishment Committee at their meeting of August 11, 2016.

APPENDICES

1. Unit 2 Level 1 Schedule
2. DRP 4-Unit Cost Estimate Summary including Variance Analysis to RQE
3. Unit 2 Cost Estimate Summary including Variance Analysis to RQE
4. Unit 2 Key Discrete Risk Summary
5. Resource Histograms
6. Funding Release Calculation


DARLINGTON
REfURBISHMENT
Aenower in Ontario
Unit 2 Refurbishment Outage
Critical Patll Windows
Close to Critical Path
ow Float Windows
Electrical Windows
Heat Transport System Windows
Turbine/Generator
Reactivity Device Windows
UNIT2REVC2
July 26,2016
SEP 2019
OCT 2019
Feedwater T/G & Condenser Scope Phase 1
100 Condenser Work & CT/HV Bushing
061 Turbine Generator Major Overhaul
HX Inspections (LPSW Side) & CT Replacement
002 Conventional Side Layup
D1711 start after Installation of Bulkhead Panels MK3, MK4, MK8 & MK9 in Window 023
052 Power Track 1/2 Replacement
039 Power Track 3/4 Replacement Window 1
047 Power Track 3/4 Replacement Window 2
Install All HTS Pump Motors
060
062 Primary Side SG Clean & Inspect
West Side SGs
East Side SGs
128 ECI Vault Work
189 Install Strainer in Boiler 4d
Pressure Tube Install progressed to below Row M
058 Complete Emergency Heat Sink pipework (E. Vault)
ToRCHP4
HTS Aux Vac Dry
035
HTS Auxiliaries - Drain Dead Legs & Purge & HTS Rehab
048 Drain & Purge
HTS Rehab
To HTS Fill
To Tie-in for Mod Vac Dry
Airlock Mtce & Testing
006
013 HTS Bulk Drain
029 HTS Vac Dry 40d
Pre-Req's
Vac Dry (Cont'd)
034 Install SG Lay-Up Primary Side
To Mod Drain
104 Vault Projects
PIP/EHS/Cyclical
Full Vault Access
027 Bulk Interference Removals
101 Remove FM Bridges & Install RTPs
111 Feeder Cabinet Removal
042 Feeder Removal
140 Dummy FB Removal
105 Vault Projects
PIP/STOP/LRV/ Cyclical
114 End Fitting Removal
064 West Side
Vault ACU Replacements
070 East Side
To Window 68 Emergency Heatsink Pipework in East Vault: must be installed after ACU work
079 Gross Air Leak Test
078 Remove Mod Dry Equip & Reconnect Mod Pipework
068 Install AA Drives
080 Fill Calandria
129 Temp Fission Chamber Guide Tube Install
140 Temp Fission Chamber Fission Chamber Install
061 Cold Testing & Establish GSS
116 CTI Removal
074 Vessel Inspection
149 Tube Sheet Bore Cleaning
115 PT Removal
098 CTI Release
117 CT Removal
118 Calandria Tube Install Series
Fuel Channel Installation Series
083 Lower Feeder Install Series
084 Fuel Load
082 RTP Removals, Bridge Replacement
085 - Shielding Rem'd - A/L Closed - Pressure Test - VVRS Balance
088 Bulkhead Removal
094 Power Escalation
093 Heat-up & Low Power Testing
092 ATC 2d
097 Bulkhead PostReqs
095 Run-up & Sync & Balance
096 High Power Testing & Turbine Testing
012 Defuel Reactor
023 Install Bulkhead
015 Crane Maintenance 2d
024 Containment Pre-test, Achieve Dew pt. & Containment Test
025 Install Shielding
017 -Install APT & End Fitting Caps -Carriage Removal
Replace Adjuster Rods
021
To STOP Installation
Nozzle Inspection & Weld Prep
045
076 Upper Feeder Installation (180 days)
071 Trial CT Install
To S/G Primary Side Inspections
072 Bellows Inspections
To Remove Mod Dry Equip.
037
028 Replace Vertical Flux Detector
073 HFD Replacements
To RCHP1
031 SA & CA Rods
007 SDS1/2 Computer Replacements
137 -Final Commissioning VVRS Phase 1 -AL & TCD Logic Mods -BU Logic Mods Phase 2
From HTS Vac Dry Complete
Mod Drain & Flush
Isolate Calandria From Main Pipework & Hookup Drying Equip.
Establish Upper Calandria Purge Flow & EW Valve Maintenance
520 D2O Management Building
038
108
103
To Below Inspections 072
To Remove Mod Dry Equip.
Instrument Air Mtce
054
From HTS Auxiliaries Vac Dry Complete
022 Remove All HTS Pump Motors
057
121
122 Moderator Valve Rehab
046 LISS Rehab
Tie in HTS Vac Dry Skid to Mod Pipework
Vac Dry Lower Moderator Pipe work
PULSW SDC HX Line Replacement
Remove Vac Dry Equip
123
124
SDC Valve Work
Aux Shutdown Cooling Pumps
To RCHP 4 HTS Fill
147 ECI Valve Mtce
089 HTS Air Hold, Fill & Pressure Test
090 HTS Operational Testing
NOTES
1. All schedule logic and level 3 schedules are not yet finalized. Therefore, this schedule and window durations are subject to change with in the Unit 2 bounding duration as per the approved November 2015 Release Quality Estimate.
EPS
Cl 3 Elec. Maintenance
Cl2Elec..MUI
CL 4 Elec. Maintenance
2. ReactorCon!,JoHoldPoint
REV C2 APPROVALS TO ISSUE
Prepared by:
Reviewed by:
Karl!n Fritz, U211j'tage DireJ >r
Concurred by:
Boris Vulanovlc, Refurbishment DOM
Approved by:

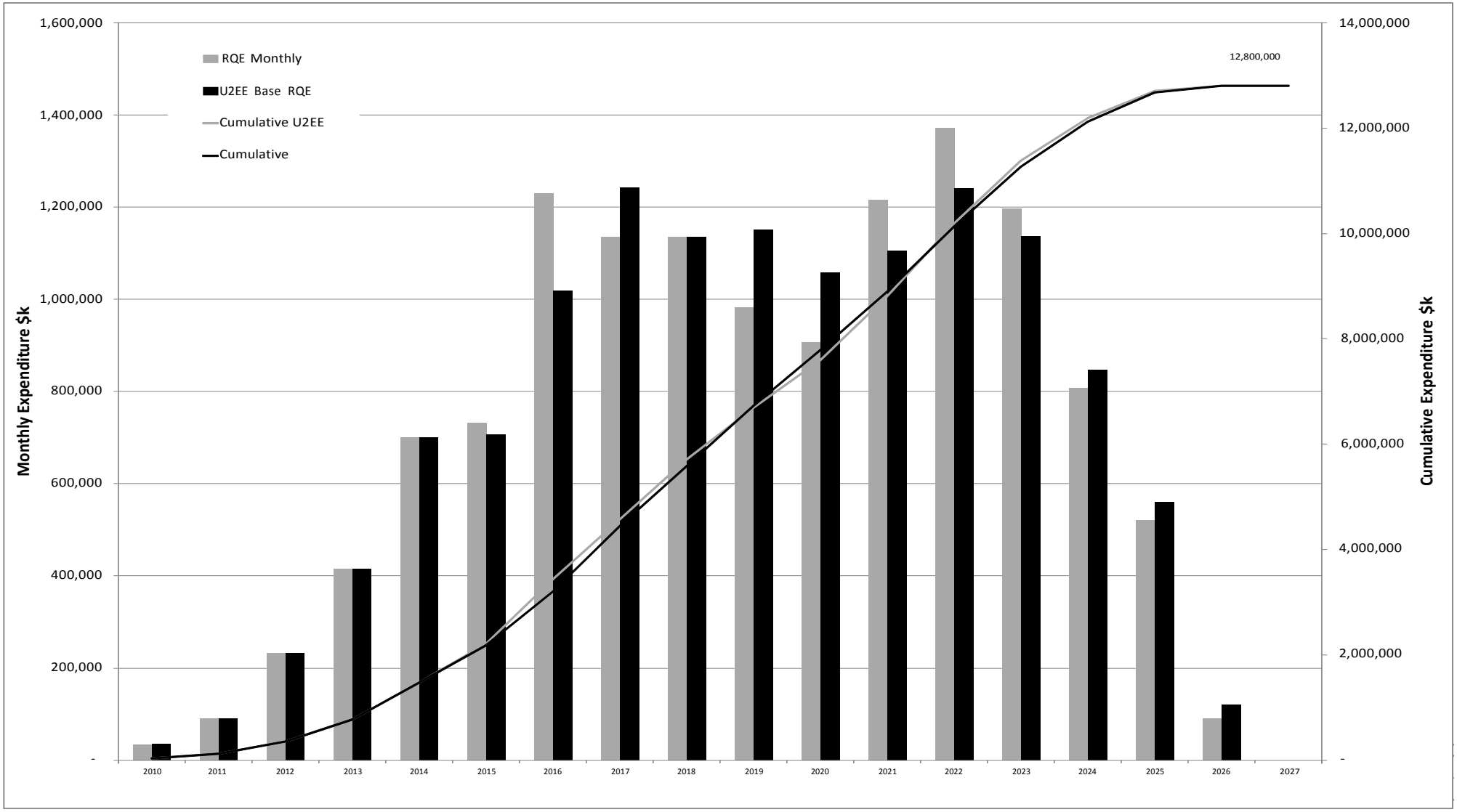
APPENDIX 2A: 4-UNIT COST SUMMARY

#	Division	RQE	Current U2EE	Variance from RQE	%
1	NR - Retubing & Feeder Replacement	4,489,335	4,494,607	5,273	0%
2	NR - Turbine Generator	862,083	865,336	3,253	0%
3	NR - Balance of Plant	570,780	587,350	16,569	3%
4	NR - Fuel Handling	186,563	166,363	(20,200)	-11%
5	NR - Defueling	50,798	54,917	4,119	8%
6	NR - Steam Generator	161,509	163,275	1,765	1%
7	NR - Specialized Projects	134,837	135,862	1,025	1%
8	NR - Shutdown, Layup and Services	232,311	197,877	(34,434)	-15%
9	NR - Unit Islanding	167,378	172,288	4,910	3%
10	NR - Waste Disposal	38,518	38,518	0	0%
11	NR - Refurbishment Support Facilities	98,114	82,901	(15,213)	-16%
12	**SubTotal Bundle Projects**	**6,992,227**	**6,959,296**	**(32,932)**	**0%**
13	NR - F&IP + SIO Projects	932,792	958,738	25,946	3%
14	**SubTotal Campus Plan Projects**	**932,792**	**958,738**	**25,946**	**3%**
15	OPG Functions + Ops & Maintenance	2,868,663	2,875,193	6,531	0%
16	**SubTotal Functions**	**2,868,663**	**2,875,193**	**6,531**	**0%**
17	Contingency	2,006,318	2,006,773	455	-
18	**SubTotal Contingency**	**2,006,318**	**2,006,773**	**455**	**0%**
19	**Nuclear Refurbishment Program**	**12,800,000**	**12,800,000**	**(0)**	**0%**

(1) All figures now include inflation & interest (RQE reported base costs in 2015, with inflation & interest "below-the-line')

APPENDIX 2B: 4-UNIT COST FLOW – U2EE vs. RQE

To be updated by September 30th, post issue of REV0 Level 1 Schedule (Sept 15th), upon which time final interest will be re-calculated



		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
RQE	RQE Monthly	35	90	233	416	701	732	1,231	1,136	1,135	983	907	1,215	1,372	1,196	807	521	90	-	12,800
	RQE Cumulative	35	125	358	774	1,475	2,207	3,438	4,574	5,709	6,692	7,599	8,814	10,186	11,382	12,189	12,710	12,800	12,800	12,800
U2EE	U2EE Total	36	91	233	416	701	707	1,018	1,243	1,135	1,151	1,059	1,105	1,240	1,137	848	560	120	-	12,800
	U2EE Cumulative	36	127	360	776	1,476	2,184	3,202	4,445	5,580	6,731	7,790	8,895	10,135	11,272	12,120	12,680	12,800	12,800	12,800

APPENDIX 3: UNIT 2 COST SUMMARY

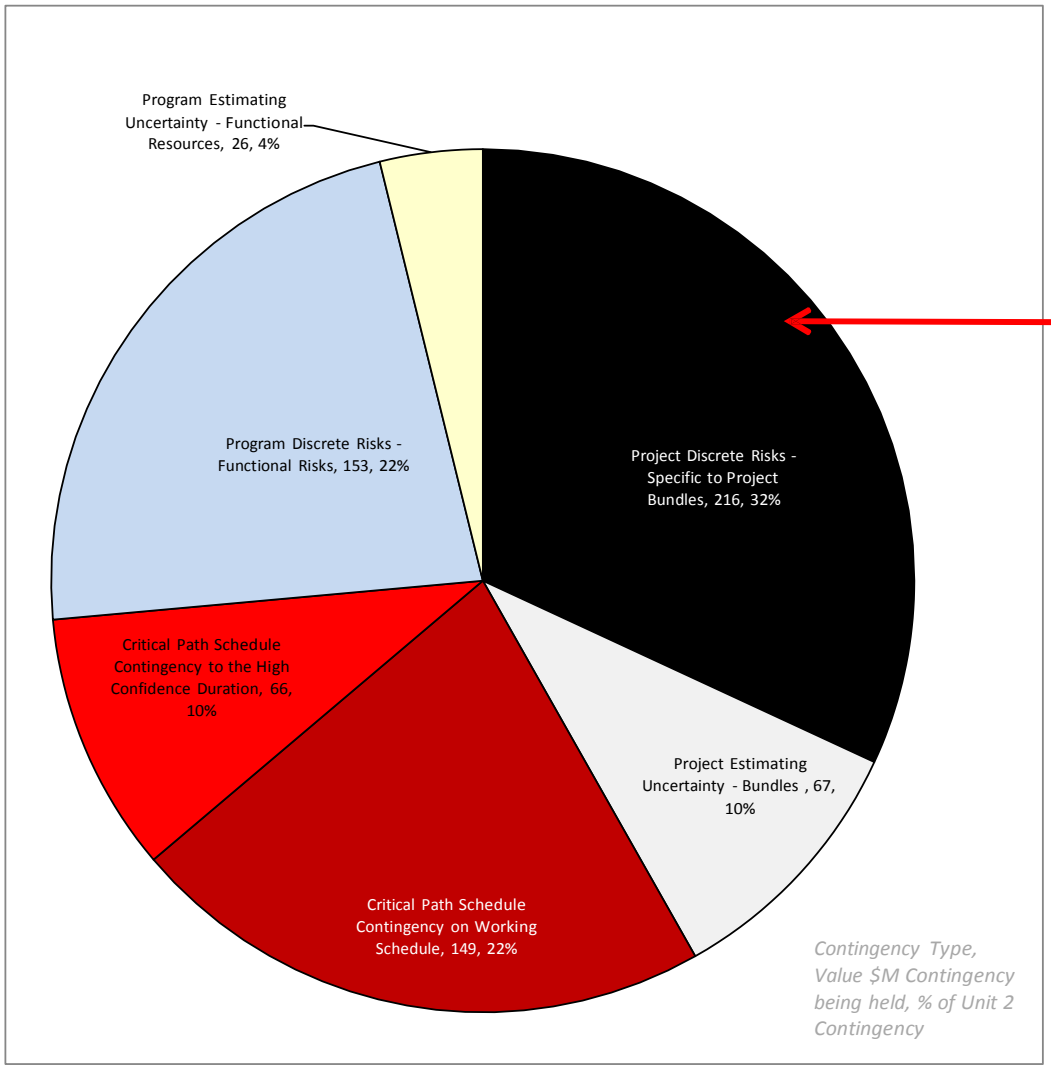
#	Division	RQE	Current U2EE	Variance from RQE	%
1	NR - Retubing & Feeder Replacement	1,143,965	1,148,041	4,077	0%
2	NR - Turbine Generator	226,164	228,012	1,849	1%
3	NR - Balance of Plant	165,731	186,299	20,568	12%
4	NR - Fuel Handling	21,498	16,448	(5,050)	-23%
5	NR - Defueling	31,544	35,978	4,434	14%
6	NR - Steam Generator	53,313	54,537	1,224	2%
7	NR - Specialized Projects	85,593	86,656	1,063	1%
8	NR - Shutdown, Layup and Services	83,371	76,354	(7,017)	-8%
9	NR - Unit Islanding	57,731	61,058	3,327	6%
10	NR - Waste Disposal	7,713	7,713	0	0%
11	NR - Refurbishment Support Facilities	35,478	36,382	904	3%
12	**SubTotal Bundle Projects**	**1,912,101**	**1,937,479**	**25,378**	**1%**
13	NR - F&IP + SIO Projects				
14	**SubTotal Campus Plan Projects**				
15	OPG Functions + Ops & Maintenance	791,583	802,114	10,532	1%
16	**SubTotal Functions**	**791,583**	**802,114**	**10,532**	**1%**
17	Contingency	689,530	677,452	(12,078)	-2%
18	**SubTotal Contingency**	**689,530**	**677,452**	**(12,078)**	**-2%**
19	**Nuclear Refurbishment Program**	**3,393,213**	**3,417,045**	**23,832**	**1%**

(1) All figures now include inflation & interest (RQE reported base costs in 2015, with inflation & interest "below-the-line")

(2) Campus Plan F&IP + SIO Projects (Unit F and Unit S) excluded from “Unit 2”, but are included in the overall Release 5b funding request.

(3) Estimate to Complete (ETC) costs for Unit 0 (Common Work) and Unit D (Definition Phase Work) are excluded from the above, but are included in the overall Release 5b funding request.

APPENDIX 4: UNIT 2 KEY RISK & CONTINGENCY SUMMARY

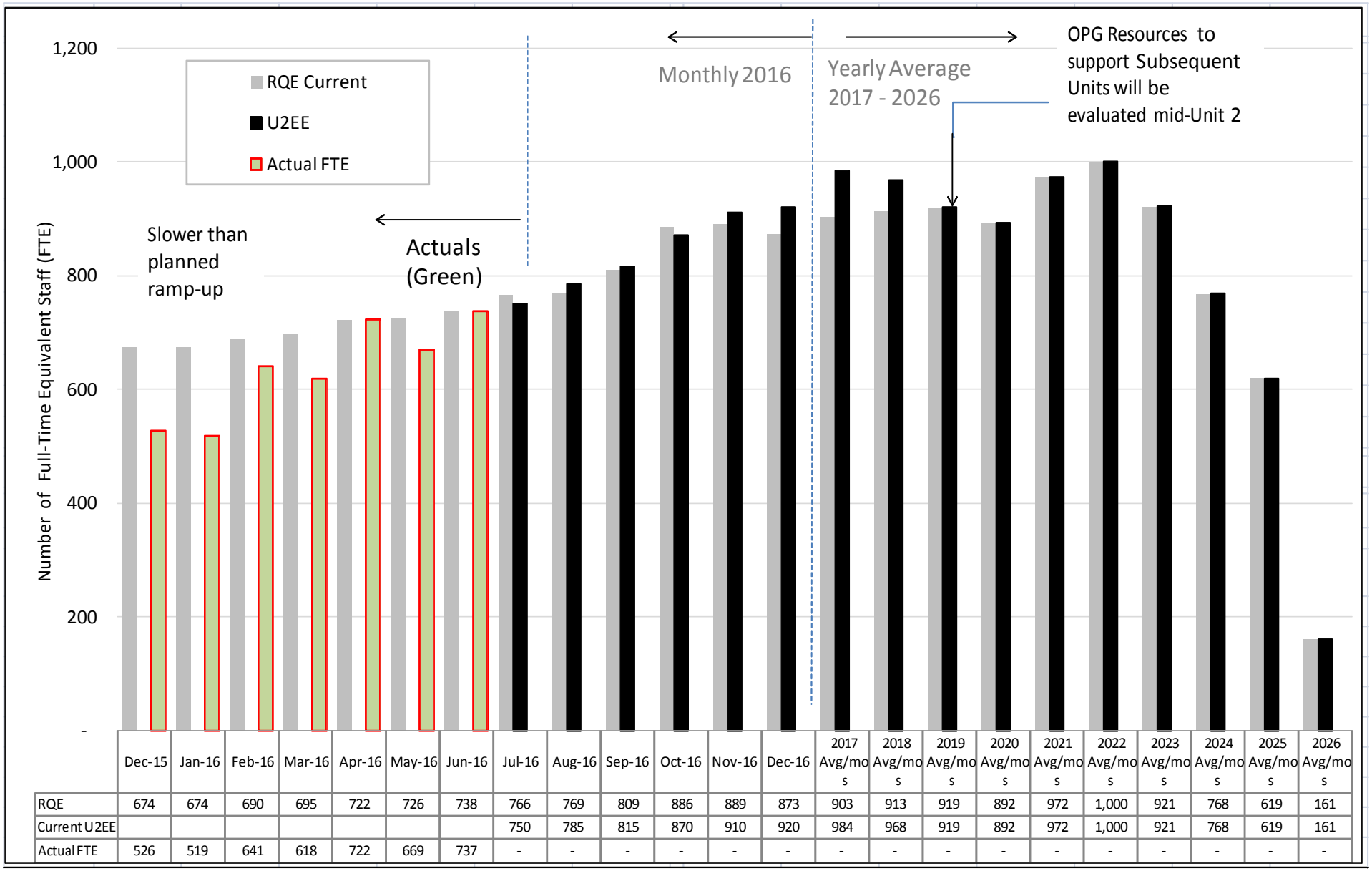


Unit 2 Discrete Top Risks by $ Value

Bucket	Bundle / Functiona	ID	Description	U2EE Unit 2 $k
Discrete Risks	Retube and Feeder	13325	Concealed Conditions [Window 167, 168]	20,565
Discrete Risks	Refurbishment Execution	683	Refurb Construction - Poor EPC Vendor performance may require additional oversight during all phases	18,381
Discrete Risks	Refurbishment Execution	783	Refurb Construction - Estimated Cost of General Services contract may be underestimated	17,190
Discrete Risks	Refurbishment Execution	TBD	Trough Management	16,487
Discrete Risks	Program Support	751	Foreign Exchange	16,006
Discrete Risks	Balance of Plant	13663	Additional BoP Resource Risk due to lack of Vendor EPC Experience	12,225
Discrete Risks	Turbine Generator	11250	TG Discovery work scope caused by inspections with impact on long lead items or major repairs	8,063
Discrete Risks	Retube and Feeder	13329	Claims from Retube and Feeder Replacement (RFR) Vendor Not already Covered in the Contract	6,594
Discrete Risks	Balance of Plant	14413	73750 Phase 2 cost escalation (Windows 122, 124, 029, 057)	6,579
Discrete Risks	Operations and Maintenance	708	Materials budget for emergent broke-fix maintenance during Shutdown, Layup and Runup	6,141
Discrete Risks	Operations and Maintenance	564	Large Potential Worker Doses due to Inadequete Internal (Alpha etc.) Hazard Characterization	6,045
Discrete Risks	Refurbishment Execution	717	Refurb Construction - Estimated Cost of RPPE Laundry may be underestimated	5,847
Discrete Risks	Retube and Feeder	13917	Insufficient Tool Quantities or Spares for RFR Execution - all causes [Potential Window 160-188]	5,619
Discrete Risks	Retube and Feeder	13860	Owner Specified Material (OSM) pricing from Unit-to-Unit Procurement [No Window Related]	4,956
Discrete Risks	Shutdown and Layup - Services	13619	SDLU Pre-requisite projects delays [No Window Related]	4,874
Discrete Risks	Shutdown and Layup - Services	14318	Quality Issues [No Window Related]	4,495
Discrete Risks	Retube and Feeder	14115	Feeder fabrication schedule delay as a result of flow element (I690) weldability challenges.	3,773
Discrete Risks	Operations and Maintenance	839	Valve Program Vendor Contract not Secured	3,690
Discrete Risks	Balance of Plant	13263	73639 - PHT & Auxiliaries - PHT & Aux - PHT Pumps Will Require Repairs	3,461

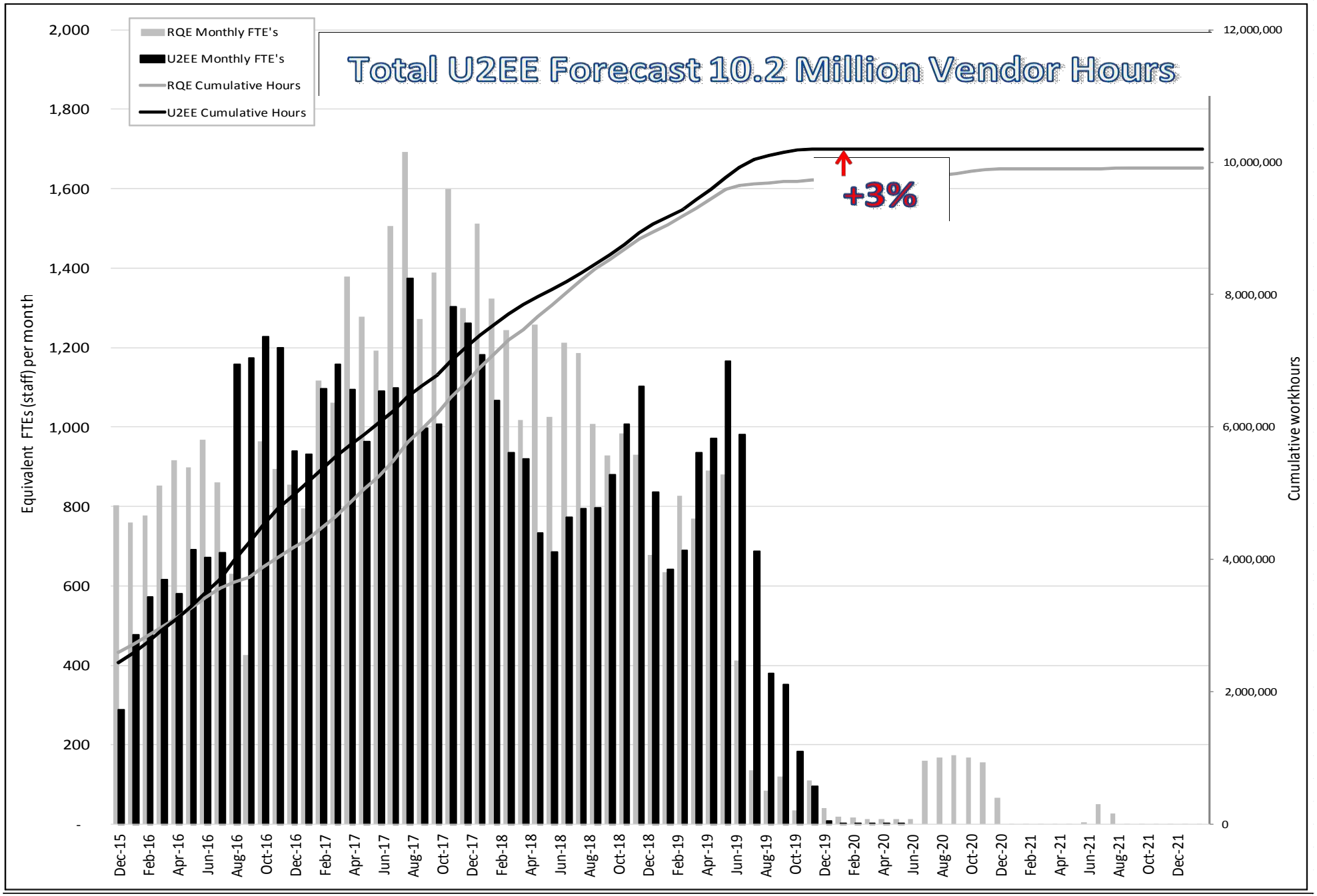
APPENDIX 5A: RESOURCE ANALYSIS – OPG RESOURCES: U2EE vs. RQE

The following chart includes OPG Project Management, Oversight and Functional Support, plus Operations & Maintenance



	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2017 Avg/mos	2018 Avg/mos	2019 Avg/mos	2020 Avg/mos	2021 Avg/mos	2022 Avg/mos	2023 Avg/mos	2024 Avg/mos	2025 Avg/mos	2026 Avg/mos
RQE	674	674	690	695	722	726	738	766	769	809	886	889	873	903	913	919	892	972	1,000	921	768	619	161
Current U2EE								750	785	815	870	910	920	984	968	919	892	972	1,000	921	768	619	161
Actual FTE	526	519	641	618	722	669	737	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

APPENDIX 5B: RESOURCE ANALYSIS – VENDOR RESOURCES: U2EE vs. RQE (UNIT 2)



APPENDIX 6: FUNDING RELEASE CALCULATION

a	*b*	*c*	*d*	*e=c+d*	*f*	*g=e+f*
#		Cumulative Release 4	Approved Release 5a (at RQE)	Cumulative Release 5a	Current Request	Cumulative Release 5b (Unit 2)
1	Unit 0 (Common)	128,000	230,701	358,701	631	359,332
2	Unit D (Definition)	1,014,997	97,062	1,112,059	139,155	1,251,214
3	Unit 2	371,382	360,995	732,377	2,007,216	2,739,593
4	**Subtotal thru U2**	**1,514,379**	**688,758**	**2,203,137**	**2,147,002**	**4,350,139**
4	Unit F (F&IP projects)	693,547	186,983	880,530	94,293	974,823
5	Unit S (SIO Projects)					
6	**Subtotal Campus Plan**	**693,547**	**186,983**	**880,530**	**94,293**	**974,823**
7	Unit 3	0	45,805	45,805	0	45,805
8	Unit 1	0	50,730	50,730	0	50,730
9	Unit 4	0	5,465	5,465	0	5,465
10	**Subtotal Other Units**	**0**	**102,000**	**102,000**	**0**	**102,000**
10	Contingency U2	0	42,699	42,699	634,753	677,452
12	**Subtotal Other**	**0**	**42,699**	**42,699**	**634,753**	**677,452**
12	**Total DNP**	**2,207,926**	**1,020,440**	**3,228,366**	**2,876,047**	**6,104,413**

^

Requested 5b **2,876,047**

CONTINGENCY

1.0 OVERVIEW

Risk management is a systematic approach for proactively identifying, analyzing, managing and responding to project risks. OPG has implemented a comprehensive and robust risk management system for the Darlington Refurbishment Program "(DRP"), a key product of which is the contingency that is included in the Release Quality Estimate ("RQE"). Contingency is an important tool for managing uncertainty and risk throughout the life of a project. The process that OPG has used to develop the DRP contingency is set out in this Ex. D2-2-7. The process that OPG will use to manage contingency during the Execution Phase is described in Ex. D2-2-9.

2.0 CONTINGENCY

Determining the amount of contingency for a particular project or program is integral to the estimating, scheduling and risk management processes.

Importantly, contingency refers to amounts that are *expected* to be expended because there are risk items and uncertainties that will occur and cannot be entirely mitigated or avoided. Contingency is included as a component of a project estimate just like any other component of a project. It is not an extra amount that will not be spent if the project goes as planned, nor is it a tool to compensate for an underdeveloped project plan. It is a necessary, legitimate and thoughtfully developed part of the estimated project cost based on residual (post-mitigated) risk and uncertainty.

Association for the Advancement of Cost Engineering ("AACE") , a leading authority in the area of cost engineering, management and estimation, defines "contingency" as an amount that is added to an estimate to allow for items, conditions or events, for which the state, occurrence or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. In addition, the AACE definition states that "contingency is generally

included in most estimates, and is expected to be expended."[1] Contingency is typically estimated using statistical analysis informed by judgment based on past experience and considers only residual (post-mitigated) risk exposures. Similarly, the Project Management Institute, a leading professional membership association for the project, program and portfolio management profession, explains that contingency allowances are part of the funding requirements for a project, necessary to account for cost uncertainty.[2]

OPG developed the DRP estimate in accordance with AACE's recommended practices for estimate classification. As part of this approach, OPG identified and classified risks and developed the contingency component of the DRP estimate based on industry best practices (including AACE guidelines). OPG retained KPMG to provide an independent review of the risk management and contingency development process used by OPG to develop the RQE for the DRP. Based on its review, KPMG found OPG's governance, methodology and approach to be in alignment with AACE guidelines and industry best practices in terms of identifying and classifying risks and using an integrated Monte Carlo-based risk analysis, as described below. A copy of KPMG's report on contingency is provided in Attachment 1 (the "KPMG Contingency Report").

3.0 CONTINGENCY DEVELOPMENT

OPG established a risk management team within the DRP organizational structure and equipped them with the necessary tools to identify, develop, manage and monitor risks associated with the DRP. The contingency estimate was developed through a detailed evaluation of (1) the uncertainties in estimating cost and schedule, (2) discrete risks relating to cost and schedule, and (3) contingent work across each project and the entire Program. This process relied upon the use of both qualitative and quantitative methods, including performance of an integrated cost and schedule Monte Carlo simulation. OPG retained a modelling expert to assist with the architecture and robustness of the model and oversee the simulation.

[1] "Cost Engineering Terminology", Recommended Practice 10S-90, AACE International, WV, rev. 2007.

[2] Project Management Institute, *Guide to the Project Management Body of Knowledge (PMBOK Guide)*, 4th ed., 2008, Section 7.1.2.6 at p. 173.

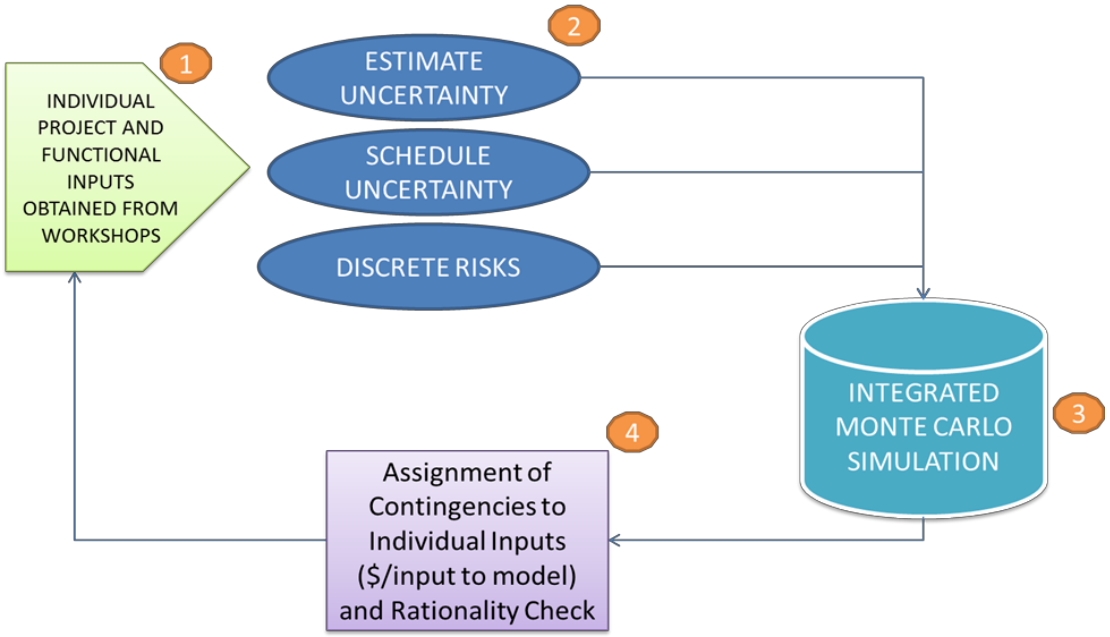
OPG's contingency estimate is based on three key contributors to contingency, namely cost uncertainty, schedule uncertainty and discrete risks.

- *Cost estimating uncertainty* is the possibility that the costs of the projects are more or less than the applicable estimates, taking into consideration the estimate classification of the base project cost (excluding discrete risk events).
- *Schedule estimating uncertainty* is the possibility that the actual schedule durations for the projects are more or less than the estimated durations (excluding discrete risk events).
- *Discrete risks* are the incremental cost and schedule impacts to the project baselines if risk events were to occur. These include risks that are specific and applied to individual project bundles, such as delays to procurement of a specific component for a specific project, as well as global Program risks that could impact the DRP in an overarching manner, such as with respect to the availability of sufficient skilled trades resources to execute the refurbishment work program.

A general illustration of the iterative process to gather, process, and refine the contingency inputs is shown in Figure 1 below.

Figure 1

Iterative Process for Gathering, Processing, and Refining Contingency Inputs



A comprehensive risk register including AACE estimate classifications for each project and detailed schedule logic was used to develop the contingency estimate. The risk register was initially developed by subject matter experts from each project team and was then vetted through a series of challenge sessions led by panels of independent subject matter experts to ensure reasonability and that the risks input to the process are legitimate and being effectively managed. Contract staff supported the contingency development process by developing the base cost and schedule estimates to approved AACE estimate classifications and by identifying risks that were incorporated in the risk registers.

The “cost uncertainty” and “schedule uncertainty” components of contingency were reviewed by the project management teams in collaboration with individual subject matter experts in a workshop environment and with reference to the AACE estimate classification and schedule durations. This practice of identifying and modeling the integrated effects of risk and uncertainty on schedule is an approach which KPMG considers to be best practice.

OPG used @Risk, a leading risk analysis software tool from Palisade Corporation, an internationally recognized leader in this field. As noted above, OPG also retained a risk modelling subject matter expert from Palisade to assist in the architecture and robustness of the model and oversee the simulation. KPMG found that such use of a risk modelling subject matter expert is considered a best practice for infrastructure projects of a similar nature and scale.

An integrated Monte Carlo simulation representing execution of the entire Program on a four-unit basis was conducted. Monte Carlo simulation is a computerized mathematical technique that replicates execution of the project thousands of times, accounting for potential realization of risk events and uncertainties, which allows quantitative analysis and decision making. It provides decision makers with a range of possible outcomes and the probabilities that those outcomes will occur to certain confidence levels. This technique builds models of possible results by substituting a range of values for any factor that has inherent uncertainty. The model is then used to calculate the results in an iterative manner, involving thousands of iterations, each using a different set of random values from the probability functions.[3] The intent is to simulate the outcome of DRP risk and uncertainty variables thousands of times and integrate these results to determine the confidence levels of contingency sufficiency. The RQE contingency estimate was a high confidence estimate based on the risk and uncertainty profile.

After initial contingency development workshops were completed and a preliminary contingency estimate was prepared, management reviews were held to validate the overall adequacy of the contingency estimate. This further ensured that the level of detail and the input of risks and uncertainties were reasonable and prudent. KPMG reviewed the inputs and simulation outputs and found that OPG developed a robust model by completing quality and data integrity checks after the contingency development workshops were held. KPMG also found that OPG's use of statistical correlations for the schedule analysis to simulate the interdependence of related activities is considered to be best practice.

[3] Palisade Corporation, *Monte Carlo Simulation* <http://www.palisade.com/risk/monte_carlo_simulation.asp>.

4.0 CONTINGENCY AMOUNTS

4.1 DRP Contingency Amounts

The detailed evaluation of cost and schedule uncertainties and discrete risks, as well as contingent work across each project and the entire DRP, enabled OPG to determine the appropriate amount of contingency to include in the RQE. The outcome of this analysis yielded that, at a high confidence level, the RQE should include $1.7B (2015$) of contingency, which is comprised of project contingency and program contingency amounts.

Project contingency is derived from the individual discrete risks and cost uncertainties managed by project directors. Project risks have a localized project impact if they occur. *Program contingency* is derived from overarching Program risks managed at the executive level that could influence the overall Program's objectives, may require Program-wide response and may have a global impact on the Program.

For a project of the size and duration of the DRP, there are a number of low probability high consequence events that could impact the Program and that are outside of the contingency determined for the Program. Due to the low probability, these items would not contribute sufficiently to a probabilistic assessment used in establishing contingency. Management has compiled a list of such events that could occur, and are beyond the ability of the project to manage or mitigate. Examples of events may include force majeure, a significant labour disruption, changes in the political environment, an international nuclear accident (Fukushima-type event) or incident, and unforeseen changes to financial and other economic factors beyond those assumed in the Program. If such an event were to occur, Management would evaluate the cost and schedule consequences of the event and provide a recommendation to the Board for approval on the appropriate response.

A breakdown of the DRP contingency amounts is set out below in Chart 1.

Chart 1

Unit Project and Program Contingency

Project	Estimate Class[4]	Project Contingency ($M)	Program Contingency ($M)	Total Contingency ($M)
RFR	2	236	381	617
Turbine Generator	2-3	195	23	218
Steam Generators	2	20	0	20
Fuel Handling and Defueling	3	25	38	63
Balance of Plant	3-5	230	0	230
F&IP and SIO	1-3	42	34	76
Project Execution and Operations and Maintenance	N/A	58	222	280
Unallocated Program Contingency	N/A	0	202	202
Total Contingency ($B)	**-**	**$0.8B**	**$0.9B**	**$1.7B**

Authorization of the use of contingency funds is strictly controlled through the Change Control Board ("CCB"), which requires an explanation of the risk or uncertainty element that has been realized and a robust approval model that requires escalation for use of any contingency funds. Additional information regarding the CCB is found under Ex. D2-2-9, Attachment 1.

4.2 Unit 2 Contingency Amounts

Of the total $1.7B of DRP contingency, $694.1M is attributed specifically to the Unit 2 refurbishment and forms part of the forecast cost of Unit 2 refurbishment. This includes $339.0M of project level contingency and $355.1M of Program level contingency, which together represent 14.4 per cent (7.0 per cent and 7.4 per cent respectively) of the total Unit 2 in-service additions for 2020.

Allocation of the total contingency across the four units was based on 'risk exposure windows', which refers to the anticipated timing for when the risks or uncertainties would be realized and associated contingency costs would be incurred. In allocating contingency to

[4] See section 2 of Ex. D2-2-8 for further information on estimate classification.

Unit 2, OPG assumed, based on industry experience, that the first unit will realize more risks than subsequent units and that lessons learned will be incorporated for subsequent units to avoid recurrence. Accordingly, approximately 40 per cent of the total DRP contingency amount was allocated to Unit 2, with the expectation that the amount of contingency required for each subsequent unit would be less than the one prior to it. A breakdown of the specific components of the $694.1M of contingency for Unit 2 is provided in Chart 2, below.

Chart 2

Breakdown of Unit 2 Contingency Amounts

Program Element	**Contingency ($M)**
RFR	117.9
Turbine Generator	81.7
Fuel Handling/Defueling	10.5
Steam Generator	8.2
Balance of Plant	96.6
Subtotal Major Work Bundles	**314.9**
Project Execution	3.6
Contract Management	0.6
Engineering	2.7
Managed System Oversight	0.4
Planning and Controls	0.8
Nuclear Safety	-
Program Fees and Other Supports	6.1
Supply Chain	0.9
Work Control	1.0
Operations and Maintenance	7.9
Subtotal Functions	**24.1**
Subtotal Project Contingency	**339.0**
Program Contingency	355.1
Total Contingency	**694.1**

As set out in section 5.6 of Ex. H1-1-1, OPG proposes that the variance between actual costs and firm financial commitments and those forecast costs and firm financial commitments underpinning the 2017-2021 annual nuclear revenue requirement approved by the OEB in this proceeding be recorded in the Capacity Refurbishment Variance Account ("CRVA"). The nuclear revenue requirement includes DRP in-service additions. In the event of any unallocated contingency at the point of in-service, the favourable revenue requirement amount will be recorded in the CRVA and returned to ratepayers in a future test period.

ATTACHMENTS

Attachment 1: KPMG Report on Contingency

Nuclear External Oversight Assessment Report of DR Team's Process for Developing the RQE Estimate

OBJECTIVE AND SCOPE

Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") have assessed the DR Team's process for developing the Release Quality Estimate ("RQE") which OPG and the DR Team have been developing since 2009. The DR Team's major focus over this time period has been the development of detailed cost estimates of sufficient quality and basis in order to establish a four-unit, program level ***control budget*** for the DR Project. In order to develop the control budget, the DR Team was required to mature its planning to the point where the cost estimates were of substance and able to be relied upon. In keeping with OPG's funding release strategy, the DR Team will continue to refine the unitized estimates for each of the four units in order to make specific funding requests through the established gating process. However, the RQE control budget will be the baseline against which both the stakeholder confidence and public trust will be measured for the life of the DR Project. In order to plan and develop the RQE, OPG developed its governance and adopted industry accepted guidelines with respect to cost estimating to facilitate the efforts of its project teams and vendors.

This report addresses the following issues related to RQE and the processes the DR Team used in developing its multiple sub-components:

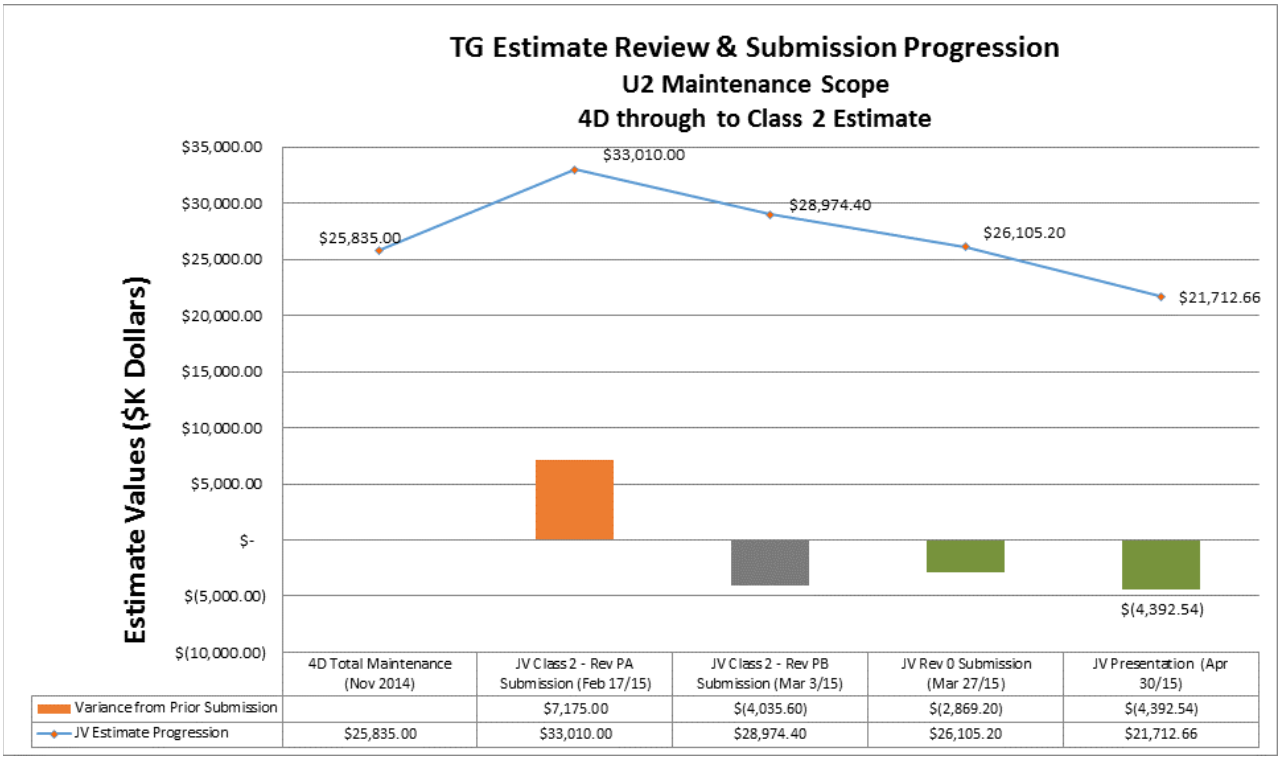
- Has OPG properly developed and supported its control budget for the DR Project in conformance with OPG's governance and applicable industry guidance, in particular those of the Association for the Advancement of Cost Engineers International ("AACE International")?
- Was the process used for RQE reasonably robust and thorough in regard to the development of the DR Project's control budget?
- Was OPG's process for developing the control budget for RQE successful in advancing the overall maturity of the effort and characterizing its project estimates?
- Did OPG develop contingency in a manner reasonably consistent with prevailing industry practices and its adopted Governance?
- Did OPG properly document the RQE Basis of its Estimate ("BOE") in a manner that allowed for reasonable vetting by Senior Management?

In the foregoing, BMcD/Modus focused on the manner in which the DR Team developed, vetted, iterated and finalized the major elements of RQE, including:

- Base or direct cost estimates for the multiple sub-projects, or "bundles", which were largely developed by OPG's vendors and vetted by OPG for purposes of establishing commercial agreements with the contractors;
- Functional costs for OPG's project management team, which were prepared by OPG;
- Project and program contingency, which was developed by OPG.

Over a period of four months, OPG's estimating team vetted 100% of the estimate comprising approximately 40,000 line items and issued over 300 comments that SNC/Aecon had to disposition. The collaborative approach taken between SNC/Aecon and OPG teams resulted in constructive exchanges on the completeness, quality and reasonability of the estimate for issues such as labor productivity factors, crew size/rates/composition and overtime factors. SNC/Aecon was responsive to feedback and dispositioned all comments, resulting in the refinement and increased quality of the Class 2 estimate.

For example, as a comparison of the base scope for the maintenance portion of refurbishment work, the graph below presents the results of the teams working through successive reviews, multiple challenge sessions, and negotiations.



The reduction of SNC/Aecon's estimate by ~25% from its initial submission provided an example of the potential results that can be achieved through an iterative and collaborative vetting process for the other project bundles.

3. CONTINGENCY

OPG has designated both project-level and program-level contingency for this project totalling $218M ($194.8M project-level and $23M program-level contingency). The $195M in project-level contingency broken down as follows: (1) $27.9M for cost uncertainty; (2) $49.9M for discrete risks identified by the Project Team; and (3) $117M for potential component replacement based on the results of concealed condition assessments on each unit's turbine generator. The DR Team set aside $23M in program-level contingency for schedule uncertainty. This project's contingency bucket was vetted and classified using the OPG estimating process. The team has fully examined the potential schedule impact of discovery work and believes it has reserved sufficient non-critical path time for major component procurement and replacement in the event such work is required.

Board Staff Interrogatory #50

Issue Number: 4.3

Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Reference:

Ref: Exh D2-2-3, Chart 1

Interrogatory

a) Describe all "off ramps" for each major work bundle. What is the governing process for OPG to determine whether to exercise the off-ramps? How will this decision be communicated to all interested parties? What are the cost categories that will be payable to the contractors upon execution of each of the off-ramps?

b) Describe what information OPG will gather, who will receive the information, when the information will be provided, and how the decision will be made whether to the exercise the off-ramp during or after the completion of Unit 2. Provide the same information for all of the other units and the process OPG will use to assess whether to exercise the off-ramps throughout the project.

c) Describe the governing process regarding the off-ramp for when a prime contractor is substantially below expectation. What does "substantially below expectation" mean? What information will this determination be based on? Who will have access to that information, when will it be provided, and who will make that decision?

d) What actions must the contractors take to recover in the event of a project schedule delay for which the contractor is responsible?

Response

a) OPG has incorporated both a termination for convenience and a termination for default clause in each of its major work bundle contracts. This allows OPG to take an "off ramp" at any time and terminate its contracts:

Termination for Default: If the contractor defaults, OPG will be entitled to terminate the agreement and exercise a number of self-help remedies. Termination for default would permit OPG to make a claim against the contractor for full contractual damages (subject to a percentage cap formula that is linked to the total contract price and certain other amounts).

Termination for Convenience: The agreement permits OPG to terminate the agreement for convenience at any time. Certain types of direct damages (but not full contractual

damages) will be payable by OPG to the contractor in such circumstances. Examples of direct damages under the contracts (with some variation between the contracts) are:

- work that has been performed to the date of the termination and for which OPG has not yet made payment;
- an equitable portion of any fees which would have otherwise been payable on the next milestone date;
- any contractor costs incurred in providing any work in progress; and
- reasonable extra direct damages suffered by the contractor arising from the termination (such as out of pocket costs for demobilization).

Each circumstance will be dealt with as appropriate based on the facts. There is no special governance process required other than compliance with the contractual terms. Formal communications will be made in accordance with the contract terms; additional communications will be made as appropriate. Prior to terminating any contract, the OPG Project Manager will request a review by OPG's Senior Management team, which includes Finance, Law and Supply Chain.

Upon decision to terminate for convenience, OPG is to provide written notice to the contractor, as set out in the contracts.

b) As discussed in L-4.3-1 Staff-44, beyond being guided by the 2013 LTEP principles for nuclear refurbishment, OPG has no insights into what factors the Government of Ontario would consider in making a decision to direct OPG to take an off-ramp.

Internally, if Unit 2, or any other Unit, was forecasting to be over budget beyond a certain threshold, OPG would be required to issue a superseding business case summary. The superseding business case summary would include information such as updated cost estimates, LUEC, and alternative proposals. The option to take an off-ramp may be one of many considered alternatives. Approval of any superseding business case summary would be sought from OPG's Board of Directors.

c) If a contractor is performing "substantially below expectation", OPG likely would terminate the agreement for default as opposed to termination for convenience.

Performance that is "substantially below expectation" will be determined on a case-by-case basis, but will include evaluation of the contractor's performance on safety, quality, schedule and cost aspects of the work being undertaken as well as their actions, or lack of action, taken to recover the performance gap.

d) OPG expects contractors to be on plan for their work. Recovery plans are required if a contractor deviates from plan and a milestone is at risk of being missed. Steering Committees consisting of senior management from both OPG and the contractor provide oversight on all aspects of contractor performance. OPG expects all defective parts of the project to be corrected at the contractor's cost. In some contracts, a schedule

incentive/disincentive regime is in place to encourage the contractors to be on or ahead of schedule.

Board Staff Interrogatory #63

Issue Number: 4.3

Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:

Ref: Exh A1-2-2
Ref: Exh D2-2-8, Attachment 1

In the current application OPG seeks the addition to rate base of $4.8B related to Unit 2 in 2020 and $743M related to supporting projects. OPG states that if actual additions to rate base are different from forecast amounts, the cost impact of the difference will be recorded in the CRVA. The evidence states that any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding. While not stated in evidence, presumably any amounts less than forecast would be recorded in the CRVA and credited to ratepayers when the account is dispositioned.

What is the incentive for OPG to reduce costs for the Unit 2 refurbishment or for the entire $12.8B DRP?

Response

OPG is an OBCA corporation whose mandate states that "OPG shall leverage its assets and expertise to generate new revenues on a commercially sound basis…."[1] Given the large percentage of OPG's assets that are regulated, a significant potential source of new revenues is the expansion of its regulated asset base. The Darlington Refurbishment Project (DRP) is a singular opportunity to renew and expand OPG's regulated asset base. This opportunity and the resulting revenues will only be realized if OPG is able to complete the entire DRP. The fact that the Government is expected to assess the on-going feasibility of DRP based on the performance of the Unit 2 refurbishment, creates a strong incentive for OPG to control costs and maintain the project schedule, consistent with safety.

The oversight provided by the OEB on this rate application and any subsequent prudence review of DRP costs in excess of forecast, will determine the amount that OPG recovers for DRP. Any cost disallowance ultimately would reduce the revenues that the company earns on its investment in DRP. Furthermore, if the project is over budget or late, management's performance will be scrutinized by OPG's Board of Directors (which has retained independent experts to provide oversight) and the Shareholder. This oversight (See Ex. D2-2-9, pp. 10 to 13), combined with OPG's management incentive program and contractor incentives included in the contracts, also drives OPG to safely complete the Unit 2 Refurbishment as quickly as possible and at the lowest possible cost.

[1] Ex. A1-4-1 Attachment 2, page 4.

The DRP is a destiny project for OPG, for the CANDU nuclear program, and for the Province of Ontario. OPG's management team and OPG's employees recognize that. If the DRP were not to succeed, there will be no, or a severely limited, future nuclear program for OPG and the Province of Ontario.

ONTARIO POWER GENERATION

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February 22, 2017

VIA RESS AND COURIER

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

Dear Ms. Walli:

Re: EB-2016-0152 – OPG Rate Smoothing Proposal

To make the increases resulting from its rate application more predictable and to reduce the average year-over-year impact on customer bills arising from its application for payment amounts for the period 2017-2021, OPG has identified a revision to O. Reg. 53/05, which if implemented would modify its rate smoothing proposal. This modified proposal was raised by the OEB and intervenors through the course of the proceeding. OPG has communicated this opportunity to the Minister of Energy (see Attachment A). The Minister has responded favourably (see Attachment B) and is pursuing the required amendments to O. Reg. 53/05.

OPG must await final promulgation of the regulatory change before it can file an amended proposal. Given the imminent start of the hearing in EB-2016-0152 and to facilitate an efficient process, OPG proposes to remove rate smoothing from the scope of Panel 2Aii Application Overview, Nuclear Rate-setting Framework, Business Planning and consider the issue at the end of the hearing through a rate smoothing panel. OPG will file an amended Ex. A1-9-1 which will identify the evidence related to rate smoothing that will be removed from Panel 2Aii and be considered by the rate smoothing panel.

Yours truly,

[Original signed by]

Barbara Reuber

cc: John Beauchamp (OPG) via e-mail
Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail

ONTARIO FOiiiER GENERATION

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February 17, 2017

The Honourable Glenn Thibeault
Minister of Energy
4$^{1}_{h}$ Floor Hearst Block
900 Bay Street
Toronto,Ontario
M7A 2E1

Dear Minister Thibeault,

Ontario Power Generation {OPG) takes great pride in providing the lowest cost electricity in the Province and is committed to maintaining this position as a way to keep customer bills as low as possible. I am writing to propose an amendment to Ontario Regulation 53/05 that will permit OPG to submit to the Ontario Energy Board {OEB) a revised rate smoothing proposal that would significantly reduce the impact of OPG's rate application on customer bills.

As you are aware, OPG is in the midst of applying to the OEB for new payment amounts covering the period 2017 through 2021. This application advances several significant Provincial initiatives. In advancing these initiatives, OPG has been focused on the safe delivery of quality projects while controlling costs. To reduce the impact on customer *bills,* our rate application already contains a rate smoothing proposal but we believe that more can be done.

Coming out of discussions between OPG, the OEB panel,OEB staff and intervenors, we have identified an opportunity to further reduce the impact of our rate application. OPG's current submission is based on a smoothing of nuclear payment amounts as is required under Ontario Regulation 53/05. We propose that Ontario Regulation 53/05 be changed to smooth the total customer bill impact arising from changes in OPG's combined payments by adjusting the amount that OPG collects over time.

If this step were taken, subject to a final decision from the OEB, this would limit the increase on the average bills to 62 cents a month per year from the currently proposed $1.05, an average of a 40% reduction in the customer bill impact arising from OPG's application. If the Province is supportive of the implementation of a regulation change, OPG would modify its rate smoothing proposal in this current application to further reduce the impact on customer bills.

I also want to assure you that we understand the concerns of our customers and will look for ways in future rate applications to maintain our position as the low cost energy provider.

There is some urgency to this request given that we are to start the hearing portion of this application in late February. I am happy to answer any questions you may have and look forward to a favourable response

Sincerely,

Jeff Lyash

Ministry of Energy

Office of the Minister

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Ontario

FEB Z 1 2017

MC-2017-321

Mr. Jeffrey J. Lyash
President and CEO
Ontario Power Generation
700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lyash:

Thank you for your letter dated February 17, 2017, outlining Ontario Power Generation's (OPG) suggested changes to *Ontario Regulation 53/05* under the *Electricity Act, 1998.* These proposed changes would help to smooth the recovery of costs associated with OPG capital investments, taking into account the overall impact on customer bills.

According to your letter, OPG's current application would have resulted in an average $1.05 per month impact on customer bills, on an annual basis for the 2017 to 2021 application period, if accepted by the Ontario Energy Board (OEB). OPG's current proposal would reduce average bill impacts to $0.62 per month on an annual basis; a 40 per cent reduction relative to OPG's current application. This aligns with the province's objectives of reducing costs for electricity customers in Ontario.

I would ask that you work with the Ministry of Energy staff in order to enable this change on an expedited basis, recognizing the urgency in finding ways to provide relief for customers and the timing of OPG's application. Please ensure that all changes are designed to mitigate cost impacts to electricity customers. I trust the OEB will review this application, in accordance with its objectives to protect the interest of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

Your proposal demonstrates leadership on the part of OPG staff, management and Board of Directors to keep the interests of Ontario ratepayers at the forefront of your corporate mission. I am also pleased to learn that this proposal was a result of the established OEB intervener process, which encourages dialogue and collaboration between all interested parties.

Sincerely,

Glenn Thibeault
Minister