Project #34000 Darlington Auxiliary Heating System:

The auxiliary heating system ("AHS") project involves the replacement of the life expired original station construction era boiler house at the Darlington site. Auxiliary heating is required as backup in order to protect station systems in the event that there is a power outage and loss of electricity and heating in the power plant on cold days. The project was undertaken to address a long standing CNSC concern regarding the adequacy and reliability of the backup heating available in the event of a four unit outage during the winter. The new AHS facility would provide a source of reliable back-up steam to the Darlington Nuclear Generating Station main heating steam in the event of a four unit shutdown, thereby mitigating potential major equipment damage due to freezing. The AHS project was reclassified to the Nuclear Operations Project Portfolio in 2015, as discussed in Ex. D2-1-10.

During EB-2013-0321, OPG updated the forecasted total project cost of the AHS project to $85.1M as set out in an execution release BCS. OPG also provided a forecast in-service amount of $75.3M in 2015.

The expected final forecast project completion cost, including the demolition of the construction boilerhouse slated for October 2016, has increased by $14.4M to $99.5M, as set out in the full release BCS included in Attachment 1, Tab 11 to this exhibit. This increase is for additional funding to complete the construction of the AHS and commissioning, demolition of the construction boilerhouse and close out. The in-service amount is $94.2M in 2016. The increase is a result of several factors with the most significant being higher than anticipated engineering-procurement-construction contract costs resulting from the following:

- Approved project change authorizations due to design and construction scope changes (+$3.9M)
- Under-estimation of vendor engineering, construction and commissioning support (+$5.8M)
- Under-estimated fabrication and installation sub-contractor costs (+$4.3M)
- Increased labour costs, e.g., lengthened schedule for completion (+$2.7M)
- Increased internal project management and support costs ($1.7M)
- Increased material costs (+$1.0M)

- Increased interest due to the longer construction schedule (+$0.3M)

These cost increases were offset by reduced project contingency (-$5.3M).

Project #25619 Darlington Operations Support Building Refurbishment: The operations support building ("OSB") (also reclassified from the DRP per Ex. D2-1-10) houses various technical services (e.g., site security, site information technology, telephone network hubs) essential to the business operations of Darlington pre- and post-refurbishment. The OSB was constructed in 1982, with a third floor added in 1988. An assessment by an external engineering firm found that many of the existing building systems are or would life expire by 2015 and concluded that the preferred alternative was refurbishment of the building.

During EB-2013-0321, OPG provided an updated forecast in-service amount of $45.1M in 2015. This was based on a forecast total project cost of the OSB refurbishment project of $47.7M (including contingency) as set out in the partial release BCS included in Attachment 1, Tab 1 to this exhibit.

The forecast project completion cost of the OSB is now $62.7M, which consists of a full release for execution of $53.0M with a superceding release for an additional $9.7M. This increase is primarily due to increased engineering, procurement and construction ("EPC") contract costs (+$8.8M) arising from under-estimation of effort to complete contract scope, including scope additions for electrical distribution equipment upgrades, additional telephone and information technology cable and hardware, upgrades to fire separation barriers and other minor changes.

In-service amounts are $55.1M in 2015 and $3.6M 2016.

Project #25609, Security Physical Barrier System: A supplemental release of $67.2M for an additional $17.7M over the full release of $49.5M was primarily due to:

- Settlement of a claim by a subcontractor to the EPC vendor (+$7.0M)
- Higher costs to complete portions of the project (+$1.1M)

Type 3 Business Case Summary

Project #: 16-34000
Project Title: Darlington Auxiliary Heating System Project

Document #: D-BCS-00120.3-10021

Project Overview

History of BCS releases and project cost estimates:

Definition Developmental Phase ($437ktotal: $427k base cost + $10k contingency) was released in November 2010 to fund completion of a Gap Analysis Report of the preferred alternative, revise Design Requirements and complete a Black Start Option Benefit Cost Analysis and Economic Risk Assessment. A previous developmental phase release had been approved for the project in 2006 but the project was deferred in 2008 to allow for completion of the Design Basis. Of the 2006 release, $904k was spent.

Definition Developmental Phase ($1,245k total: $1,094 base cost + $151 k contingency) was released in October 2011 to fund the completion of the preliminary site investigation, and Request For Proposal (RFP) process for the Engineer, Procure, Construct (EPC) Contract.

Full Definition Phase ($4,850k total: $3,980k base cost + $870k contingency) was released September 2012 to complete modification planning and initiate engineering of the new AHS.

Partial Definition Phase ($33,432k total: $27,349k base cost + $6,083k contingency) was released in November 2012 to fund the detailed engineering, major component procurement and construction of the new AHS Boilerhouse.

Partial Definition Phase ($42,407k total: $36,611k base cost + $5,796k contingency) to fund completion of Engineering; Materials Procurement; Facility and Tie-ins Construction, Commissioning, AFS and EC Close-out of the new AHS; EPC Contract Award for Demolition of existing CBH, and Modification Planning and Detailed Design for Demolition of CBH.

Full Execution Phase – This BCS ($17,126k total: $16,626k base cost + $500K contingency) to fund completion of Facility and Tie-ins Construction, Commissioning, AFS and EC Close-out of the new AHS; and Complete demolition of the Construction Boilerhouse (CBH).

History of scope and schedule changes:

The total project cost has increased from $85,102k to $99,497k as a result of:

- Additional OPG Costs to support the extended Project duration from March to October for Available for Service of the New AHS.
- Additional support from Project Control Center to provide an interface with the Station to support tie-in work.
- Additional Contract for a Boiler Subject Matter Expert to augment the Project Team.
- Underestimation of the OPG Radiation Protection support required for the In-Station installations of Steam, Condensate and High Pressure Demineralised Water.
- Engineering costs have also increased substantially due to:
  - Underestimation in design complexity,
  - Late receipt of Vender Information to support design,
  - Underestimation of the Contractual obligations per the Contractor Owner Interface Requirements,
  - Addition of a Chemical Storage Annex due to an undersized building footprint,
  - The large number of Requests For Information between Constructor and their Design Agency.
- Engineering and Construction costs for the Steam and Condensate lines to go through the Security Fence instead of under the Security Fence to minimize risk of buried services encountered utilizing directional boring technology,
- Underestimation of dewatering costs,
- Underestimation of material and construction costs. Several major material items, including boilers and auxiliary equipment, required custom design to accommodate the limited space of the building footprint, which was not part of the original bid by the Contractor.
- Procurement and Construction proceeding based on a staged release of Engineering packages. This led to inefficiencies in material procurement and construction activities.

The overall Project schedule has been impacted as a result of the challenges identified above. The Engineering completion milestone in the previous BCS of August 11, 2014 has been changed to June 12, 2015.

The new AHSF Available for Service is scheduled for October 31, 2015.

- Mischaracterized the nature of these estimates by assuming anything provided by a contractor was at a very high level of maturity (Class 3/2) when such estimates were based on conceptual (at best) engineering, meaning these estimates could not have been better than Class 5 (-50% to +100%) in nature;
- Failed to establish accountability standards for the contractors;
- Failed to identify or mitigate known risks;
- Did not effectively react to problems when they materialized and accurately and timely report the extent of cost overruns, schedule delays and scope increases to senior management;
- The P&M Team did not seek to lock down the scope at start of this work and allowed the "customer" – Operations and Maintenance – to make significant changes to the design that were not properly understood, quantified or captured in subsequent reports to senior management; and
- The ESMSA contractors contributed to the problem by not transparently reporting or timely identifying how these projects were evolving and failing to provide any reliable metrics—cost, schedule or otherwise – that informed OPG of these brewing problems.

2. Indicative Projects - D2O Storage and Auxiliary Heat

In our analysis, BMcD/Modus examined five separate projects in detail, and each exhibited some or all of the management issues to some extent. Attachment C is a brief summary of each of these projects' cost overruns.

The management failures we observed were most evident and acute with the D2O Storage and AHS projects. These projects were the "pilot" EPC projects for the ESMSA contractors—[redacted] In both cases, P&M sought the Board's full funding approval at a point when very little design was done, only to have to later seek additional funds from the Board once design had matured.

a. The Flawed Bidding/Estimating Process

P&M's management failures can be seen throughout the planning and execution phase of the project. Notable from OPG's initial negotiation and acceptance of bids for this work is P&M's mischaracterization of the vendors' estimates in the approved Business Case Summaries ("BCS"). In August 2011, OPG produced a BCS for D2O Storage that estimated its cost at $210.6M, [redacted]. At the project's next gate in June 2012, the estimated cost had dropped from $210M to $108M. However, BMcD/Modus could not find any attempt by P&M to rationalize or otherwise explain how the cost estimate for this building was cut virtually in half from one approval gate to the next. Moreover, the estimate for design and construction was $52.2M, which P&M characterized as a "Class 2 Estimate" despite the fact that at the time of the estimate, Black & McDonald had little experience with this type of construction and had performed no engineering or scope definition. Thus, this estimate was more likely a Class 5 Estimate. In retrospect, it is likely that the initial $210M estimate was more accurate; however, it is certainly clear that the approved $108M estimate should not have had any greater accuracy attributed to it, since it was not based on a significantly greater level of project maturity. Likewise, the AHS BCS was termed a "Class 3" Estimate, though it was similarly immature.

This estimate classification drove P&M to vastly underestimate the amount of contingency associated with each package. There is no evidence that P&M engaged in the type of vetting of the estimates that we would expect on projects of these size and importance. From interviews with the current P&M staff and the contractors, it appears that these initial BCS estimates were poorly characterized as part of a deliberate management strategy directed by the former VP of P&M. P&M's managers told us that the contractors were challenged to reduce their bid prices and remove all contingencies for unknowns, despite the extreme immaturity of project definition underlying their respective bids. As

an example, for the D20 Storage project, Black & McDonald was told to remove from its contract price any contingency for unforeseen soil conditions, even though there was a high likelihood that there would be contaminated soil issues. Moreover, P&M clearly overvalued price as a consideration in the contractor selection process, especially in light of the fact that the work was going to be performed on a cost-reimbursable basis and the bid prices were not binding.

P&M gave only token consideration to determining which contractor had a better approach for executing the work. P&M chose the "low bidder" even though the other contractor's qualifications and project approach were viewed more favorably. Thus, P&M created the conditions for a perfect storm of cost and schedule overruns. Because the work is largely based on a cost-reimbursable target price with no caps on size, P&M's artificial beating down the contractors' prices in the bid phase was a Pyrrhic victory: P&M's actions did not reduce cost and only served to deprive senior management of realistic cost projections for this work. The budgets for these and other F&I projects were nothing more than paper barriers that were easily surmounted as the design work continued to generate more complex (and expensive) work.

b. Lack of an Integrated Schedule

Until April 2014, the P&M project teams for D20 and AHS were working without a reliable, integrated Level 3 Schedule. Many on the project and throughout the OPG organization were given a false impression that the Campus Plan Projects, and D20 in particular, had a year of float, and so on-going delays had no impact on the Project. The delays to D2O Storage's schedule were not forecasted by the project team and were simply reported after the fact. By this point, the schedule had already slipped so that engineering was on its way to an 18-month projected overrun of an original 11-month schedule. However, without a resource-loaded, level 3 schedule, it was impossible to assess the status of the project, let alone calculate with any accuracy any remaining float.

One of the strategic initiatives was implemented by the new P&M VP was to improve the projects' schedules. This endeavor allowed the project team to see that D20 Storage was actually projected to be completed on April 26, 2016, more than a year after the original April 15, 2015 deadline. Furthermore, once known risks are factored in, it is likely that the D20 project can only achieve this revised date if some of the schedule durations are accelerated—at an additional cost. Even then, these efforts will not improve completion of the schedule by much, but will increase the probability that the April 2016 date can be met. However, none of this would be known if efforts had not been made to improve the schedule.

c. Risk Management

Based on our observations, it appears that all P&M's identification of risks is a "check-the-box" activity due the fact that having a list of risks is a prerequisite to obtaining a funding release. P&M does not actively manage its on-going risks as a part of an effective risk management program. As an example, the risk sections of the D20 and AHS BCSs consist of lists of potential risks and some evaluation of their nature, but it is not apparent that these risks in any way influenced the calculation of these projects' contingency, nor are there any regular reviews or updates of these risks until required to do so in order to pass a gate and obtain a funding release. Once a project obtains full funding for execution, very little, if any, attention is paid to day-to-day risk management, including the ongoing identification of new risks and opportunities as well as the formalized implementation of risk mitigation strategies. Additionally, there is no structured or defined risk program management oversight (such as the NR Risk Oversight Committee).

A recent self-assessment performed by the NR Management Systems Oversight group (SA RF13-000855 dated January 20, 2014) identified perceptions (opinions) of several P&M managers that included the following: "[D]evelopment and use of a Risk Register is seen as purely administrative and not adding value to the Project Managers." This suggests a lack of understanding of the value of a risk management program or lack of acceptance, which can be addressed by effective training and indoctrination. However, risk management training is virtually non-existent in the P&M organization in distinct contrast to several years ago when quarterly workshops were regularly conducted.

d. The Gate Process and Failure to Report Cost and Schedule Increases to Senior Management

BMcD/Modus next explored the relative effectiveness of the gate process for this work, and found that while the process in concept is a good one, it suffers from problems in execution. The BCS documents for D2O Storage and AHS were inconsistent in presentation of key information on cost, risk and scope. As these projects progressed, P&M's management failed to provide visibility to OPG management of the extent or nature of project cost increases. Most notably, P&M failed to update its project reports during the design phase to reflect cost increases due to scope changes in the projects.

AHS provides a critical example. On November 12, 2012, P&M presented its Gate 3A package for approval and full funding release (except for a small portion of costs to be approved in 2014). The P&M Team's gate presentation characterized the AHS cost estimate as a Class 3 estimate in the amount of $45.6 M. P&M included [redacted] of contingency in the $45.6M estimate, of which [redacted] was identified as having a 100% chance of occurrence. P&M expressed an "85% confidence level" in this cost estimate and assessed there were [redacted] days of schedule contingency in the estimate—despite the fact that the full scope of the project was not known at that time because detailed engineering had not started. The option of building a new AHS was preferred over seven alternatives, based primarily on the projected cost. At the time of this gate, the project had spent $1.46M.

Between this gate and January 2014, ES Fox engaged in the design of the AHS, scope changes caused the cost to increase from the initial $45.6M estimate to $79.9M. This cost increase is largely attributable to two causes: (1) remediation of contaminated soil that as of the time of bid was known by both OPG and the contractor to be of poor quality; and, (2) prescriptive design requirements that served to make a stock steam boiler design follow nuclear Engineering Change Control ("ECC") processes, which caused an increase in the size, complexity and nature of the work. Moreover, these design requirements and the overall length of the design phase, coupled with the soil issues, has frittered away virtually every day of float.

The fact this project had so substantially changed from the original BCS was not accurately or timely reported to management. The failure of the gate process was that the Gate Review Board members did not provide adequate oversight in ensuring that the AHS project team had a reliable estimate, schedule, and well-defined scope prior to approving the gate and recommending a funding release. As of January 2014, P&M had already expended nearly $20M, or more than half the approved budget excluding contingency, even though the design was not complete and no construction had begun. However, during this entire time, P&M's estimate at completion ("EAC") in all of the DR Project's and Campus Plan reports ***never varied*** from the approved BCS amount. Moreover, the DR Project's Program Status Report for March 2014 showed the AHS at 49% spent with a CPI of 1.10 and an SPI of 1.0, clearly not an accurate representation of the Project's status. Part of this failure was based upon some of the P&M project managers' mistaken belief that the reported EAC amounts should not be changed until additional funds had been approved for the projects. This lack of accurate reporting has deprived senior management and the Board the option of revisiting the original BCS analysis in order to determine if building a new AHS facility continues to be the preferred option—and if not, change course. This is particularly true in light of the fact that as of November 2012, three of the competing options to building AHS were priced at less than $50 M.

D2O Storage provides a very similar example at a much higher overall cost. The cost variance progression from D2O Storage began with an original approved BCS of $110M, based upon estimated contractor costs of approximately $77.8 Million. The ES Fox team and design solution were both preferred but Black & McDonald was chosen entirely because its price was $30M less even before P&M further drove Black & McDonald's estimate down.

D2O Storage's engineering effort was originally scheduled for 11 months, and was supposed to be completed by July 2013. However, even today, engineering is not complete and is projecting to extend to a total duration of 29 months. The P&M team provided sporadic updates to the design milestones as they continued to be missed but failed to convey the potential consequence. In August 2013, P&M reported that CNO Milestone 73472M0015, "D2O Modifications –

Detailed Design Complete" was expected to miss its planned completion date of August 21, 2013 **by four months** though stated, "there is no impact to the critical path."[4] As of this same meeting, an action was recorded to "confirm the timing for integration" of the D2O Storage schedule into the master C&C Schedule, the follow-up to which indicated that the schedule would not be available for integration because "it falls short of our requirements for several parameters."

In September 2013, P&M reported in the Program Status Report that:

> Due to the change in design for the connection of the new tanks to the existing, significant additional design work is required. This change of design was required to address water hammer issues with the initial plans which could not be resolved without a significant change in design. A new underground tunnel connecting the two buildings will now be utilized to connect the two buildings.[5]

However, this "significant" design change was not highlighted as a major risk item in P&M's reporting, and P&M maintained the same EAC for D2O Storage despite having this information in hand. P&M also maintained that there was no impact to the critical path, even though P&M again admitted that the vendor had yet to produce a detailed schedule, which begs the question how could one arrive at such a conclusion regarding float without a reliable schedule.

P&M first reported a variance to the D2O Storage budget in October 2013, which coincided with months of mitigating adverse soil conditions and failing to meet the schedule for tie-ins for the TRF outage. Black & McDonald presented a high-level cost estimate that showed approximately $49M of increases in foundation work and engineering in October 2013, though this estimate was characterized as a work in progress. This estimate was increased by $5M in December 2013. P&M finally updated the D2O Storage EAC in the January 2014 DR Program Status Report from $95M to $122.7M, though simultaneously, P&M issued a report to the Nuclear Executive Committee ("NEC") showing a forecasted EAC of $152M. Thus, P&M's first reporting to senior management and other OPG stakeholders of any impact of the design changes that had been brewing for nearly two years was inconsistent at best.

In January 2014, Bill Robinson required Black & McDonald to update its costs. Black & McDonald committed to an estimate of $94M (compared to its original contract of $67M), which with OPG's costs was ranged by P&M at a total of $150-170M, including OPG contingency and financing costs. After coming on board, P&M's new VP required Black & McDonald to prepare a bottoms-up, high confidence schedule and budget based on the high level of engineering completion. Black & McDonald's output has trickled in. [redacted] Black & McDonald has broken down the cost increases into several categories, including: additional scope ($85.4M), changed assumptions ($14M), soil remediation ($17.3 M), delays to the schedule resulting in acceleration ($9.8 M) and inclusion of items that were either missed or misestimated in the original estimate ($31 M). Black & McDonald characterized this estimate as a Class 4 even though: (1) the design is 80% complete; and (2) Black & McDonald had just provided a Level 3 schedule for the remaining work which they claimed was comprehensive. Based on these two data points alone, Black & McDonald should be able to produce at least a Class 2 estimate at this time. [redacted].

Moreover, throughout 2011-13, P&M did not require Black & McDonald to timely update costs and provide visibility to the cost of these design changes as they were occurring; thus, as with AHS, P&M's management allowed the contractors

[4] DN Refurbishment Program Status Report Meeting, August 21, 2013
[5] DN Refurbishment Program Status Report Meeting, September 18, 2013

to run up the tab and incorporate a flood of OPG stakeholder generated late design changes without adequate checks and balances or understanding of the magnitude of these changes.

As a direct consequence of P&M's failure to report these cost and schedule variances, senior management was deprived of the ability to:

- Stop the design changes that led to these increases;
- Stop the project entirely and resort to one of the other evaluated options;
- Identify and characterize the cost increases that are not related to Refurbishment and subject these changes to the same value-enhancing criteria as the remainder of the DR Project's work; and
- Mitigate the impact of the schedule delays and overruns.

Thus, the consequences to OPG are two projects that may cause external stakeholders to question OPG's management prudence.

e. Vendor Performance Issues

[redacted]

Board Staff Interrogatory #71

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 D2-2-10, Chart 1

OPG has indicated that it has reclassified a number of projects from DRP to the Nuclear Operations Portfolio.

a) Please confirm that the following table shows all the projects that have been reclassified and the correct total cost.

Project	Project #	Total Project Cost ($M)
Darlington Operations Support Building Refurbishment	25619	62.7
Darlington Auxiliary Heating System	34000	99.5
Emergency Service Water Pipe and Component Replacement	73397	6.7
Primary Heat Transport Pump Motor Replacements/Overhaul	73556/80144	129.5
Highway 401 & Holt Road Interchange	73706	31
Total		329.4

b) As noted in the EB-2013-0321 Decision with Reasons, issued November 20, 2014, the estimated total cost of the DRP at that time was $12.9B (including interest and escalation). OPG has removed projects from the DRP scope, yet the total cost for the DRP is still $12.8B (including interest and escalation) (reference D2-2-8, Chart 3). Please explain why the total cost of the DRP has not been reduced for these reclassified projects.

c) Please explain further the rationale for reclassifying these projects from the DRP to the Nuclear Operations portfolio. Does OPG anticipate reclassifying any further projects?

Response

a) OPG confirms that the table shows all capital projects that have been reclassified as Nuclear Operations portfolio capital projects, as noted in Ex. D2-2-10, pp. 10-11. With the exception of the Highway 401 & Holt Road Interchange, the total project cost for all other projects listed in the table is correct. As stated in Line 32 of Table 1 in Ex. D2-1-3, the total project cost for the Highway 401 & Holt Road Interchange is $28.6M.

b) The main purpose of the Release Quality Estimate (RQE) was to prepare a high confidence cost and schedule estimate based on the final scope to be managed during the Darlington Refurbishment Program (DRP). The results of RQE are a high confidence estimate for which the DRP's performance will be measured against.

The DRP cost estimate considered in EB-2013-0321 was prepared while the project was still in the Definition Phase. The cost and schedule estimates were not as well developed with several estimates still at the conceptual levels (Class 5 or 4). The final scope for DRP had not been established. For the 2015 RQE Business Case, OPG had an overall Class 3 estimate with the majority of projects at Class 3 or 2 based on a fully defined project scope, and had developed an initial integrated schedule including all contractors and scopes of work and was able to determine the critical path through the Unit 2 schedule (see L-04.3-2 AMPCO-85).

There were a large number of changes in the DRP estimate, including removal of the reclassified projects, between the estimate considered in EB-2013-0321 and the high confidence RQE.

c) Please see L-2.2-1 Staff-008, part c).

As part of the development of the RQE, OPG evaluated DRP scope to ensure that it was work that had to be done to extend the life of the Darlington units and that the work could not be done as part of normal life cycle management program. Where work could be done at another time and/or where it could be done as part of the normal station life cycle management program, it was reclassified to the Nuclear Operations portfolio.

Darlington Operations Support Building (OSB) Refurbishment was reclassified because it provides services that support the daily operations of the entire station. The project provides office space for operations support staff, technical services, security systems, IT, telephone network hub etc. to the station.

Darlington (DN) Auxiliary Heating System was reclassified because it provides reliable back-up steam to the entire station when it was placed in service. Back-up steam is needed to support irregular conditions such as an event where all four turbine units are shut down in the winter, to mitigate potential major equipment damage due to freezing.

The Emergency Service Water Pipe and Component Replacement was reclassified because the project was required to ensure a safe and reliable supply of emergency service water before, during and after refurbishment.

The Primary Heat Transport Pump Motor Replacements/Overhaul was reclassified because the work was required to be completed as soon as possible (prior to refurbishment outages on certain units) in order to maintain station reliability.

The Highway 401 and Holt Road Interchange Project was reclassified because the completion of this project was necessary to provide improved traffic flow for peak staffing during regular planned outages as well as during refurbishment.

Now that the scope of the DRP is set as per the RQE, OPG does not anticipate reclassifying any further projects.

Chart 1

Reconciliation of F&IP Project List to EB-2013-0321 Ex. D2-2-1, Tables 3 and 4

Project	Project Number	EB-2013-0321	EB-2016-0152	Total Project Cost based on approved project BCS ($M)
Projects >$20M				
Heavy Water Storage and Drum Handling Facility	31555	DRP	DRP	381.1
Water & Sewer Project	73802	DRP	DRP	57.7
Darlington Energy Complex	73803	DRP	DRP	105.4
Retube Feeder Replacement Island Support Annex	73810	DRP	DRP	40.7
Refurbishment Project Office	73815	DRP	DRP	99.9
Darlington Operations Support Building Refurbishment	25619	DRP	Nuclear Operations Portfolio	62.7
Darlington Auxiliary Heating System	34000	DRP	Nuclear Operations Portfolio	99.5
Electrical Power Distribution System	73821	DRP	DRP	20.8
Projects $5M - $20M				
GM Facility Interim Office Leasehold Improvements	73806/ 73814	DRP	DRP	9.3

In addition to the projects in the table above, the following projects were reclassified as Nuclear Operations Portfolio projects:

- Emergency Service Water Pipe and Component Replacement (Project 73397, Ex. D2-1-3, Table 2d)
- Primary Heat Transport Pump Motor Replacements (Project 73566/ 80144, Ex. D2-1-3, Table 1)
- Primary Heat Transport Pump Motor Overhaul (Project 73566/ 80144, Ex. D2-1-3, Table 1)

- Highway 401 & Holt Road Interchange (Project 73706, Ex. D2-1-3, Table 1)

2.4.5 Project Variance Explanation

This section provides an explanation for F&IP greater than $20M for which total actual or forecast project cost variances exceed 10 per cent. Explanations are provided for the following projects:

- Heavy Water Storage and Drum Handling Facility (section 2.4.5.1)
- Water and Sewer (section 2.4.5.2)
- Electrical Power Distribution System (section 2.4.5.3)

Variances for F&IP are managed as part of the overall DRP. As presented in Ex. D2-2-8, F&IP represent 5 per cent of the overall DRP. There is $76M total contingency in the DRP budget that recognizes the risks associated with F&IP and SIO. The DRP is expected to be delivered on budget and on schedule, notwithstanding the variances described below.

Facility and Infrastructure Projects are significantly different from the Nuclear Operations Portfolio projects that OPG has undertaken in the past and from the unit refurbishment program. They are new designs of complex facilities constructed on a brownfield site. For instance, there are more engineering changes (discussed in section 3.1 of Ex. D2-2-5) required for F&IP than are required for the entirety of the Unit 2 refurbishment.

2.4.5.1 Heavy Water Storage and Drum Handling Facility

Overview

The purpose of the Heavy Water Storage and Drum Handling Facility (the “Heavy Water Facility”) is to provide heavy water storage and processing capability for the removal of heavy water from the Darlington units during refurbishment and the management of heavy water during normal operations. Heavy water, when used in a nuclear reactor, becomes radioactive material. As a result, effective management and controls are required to avoid spills and to manage potential radiological safety and environmental consequences.

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit D2
Tab 1
Schedule 3
Table 1

Table 1
Capital Project Listing - Nuclear Operations Facility Projects
Projects ≥ $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project Number	Category	Start Date	Final In-Service Date	Total Project Cost[2] ($M)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M)	In-Service 2016 ($M)	In-Service 2017 ($M)	In-Service 2018 ($M)	In-Service 2019 ($M)	In-Service 2020 ($M)	In-Service 2021 ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		ONGOING PROJECTS FROM EB-2013-0321														
1	DN	Operations Support Building Refurbishment[3]	25619	Sustaining	Mar-09	Oct-15	62.7		53.0	62.7	3.6	0.0	0.0	0.0	0.0	0.0
2	DN	Class II Uninterruptible Power Supply Replacement[4]	31412	Sustaining	Jan-11	Jun-25	55.1	31.1			7.0	6.5	9.4	6.5	1.6	7.6
3	DN	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment[4,5]	31508	Regulatory	Sep-11	Sep-17	52.9	51.9			17.0	13.8	0.0	0.0	0.0	0.0
4	DN	Improve Maintenance Facilities at Darlington	31717	Sustaining	Aug-07	Oct-13	43.2		43.2		0.8	0.0	0.0	0.0	0.0	0.0
5	DN	Secondary Control Area Air Conditioning Unit Replacement[4]	33621	Sustaining	Feb-09	Apr-17	28.3	25.8			10.3	6.1	0.0	0.0	0.0	0.0
6	DN	Chiller Replacement to Reduce CFC Emissions	33631	Regulatory	Jan-04	Jan-13	30.0		30.0		0.0	1.2	0.0	0.0	0.0	0.0
7	DN	Major Pump-sets Vibration Monitoring System Upgrades[4]	33819	Sustaining	Mar-06	Jul-21	23.8	9.6			0.0	0.0	5.2	4.6	4.5	4.4
8	DN	Shutdown System Computer Aging Management[4]	33955	Sustaining	Nov-06	May-16	20.3		20.3		2.0	0.0	0.0	0.0	0.0	0.0
9	DN	Standby Generator Controls Replacement	33973	Sustaining	Dec-06	May-17	39.6	32.4			17.9	8.7	0.0	0.0	0.0	0.0
10	DN	Digital Control Computer Replacement / Refurbishment / Upgrades	33977	Sustaining	Sep-03	Dec-18	24.9		22.1	24.9	0.0	2.0	1.8	0.0	0.0	0.0
11	DN	Auxiliary Heating System[3]	34000	Regulatory	Mar-06	Apr-16	99.5		99.5		94.2	0.1	0.0	0.0	0.0	0.0
12	DN	Primary Heat Transport Pump Motor Capital Spares[4]	36001	Sustaining	Sep-11	May-15	30.8		12.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0
13	PN	Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure[6]	41023 49247	Sustaining	Nov-09	Mar-16	38.6		28.8	38.6	17.0	0.0	0.0	0.0	0.0	0.0
14	PN	Pickering A Fuel Handling Single Point of Vulnerability Equipment Reliability Improvement	46634	Sustaining	Feb-11	Mar-16	27.3		27.3		3.8	2.5	0.0	0.0	0.0	0.0
15	PN	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment[4,5]	49158 49299	Regulatory	Sep-11	Aug-16	58.0	47.2			21.0	10.5	0.5	0.0	0.0	0.0
16	SEC	Physical Barrier System	25609	Regulatory	Nov-05	Dec-13	67.2		49.5	67.2	0.5	0.0	0.0	0.0	0.0	0.0
17		**Subtotal**					702.2				195.1	51.5	16.9	11.2	6.0	12.0
		COMPLETED/DEFERRED/CANCELLED FROM EB-2013-0321														
18	PN	PB Standby Generator Governor Upgrade	49109	Sustaining	Oct-05	Jan-15	22.8		23.3		0.0	0.0	0.0	0.0	0.0	0.0
19	PN	Modify/Replace Fiber Reinforced Plastic Components During 2010 Vacuum Building Outage	49285	Sustaining	Nov-09	Jun-10	17.7		12.8	24.5	0.0	0.0	0.0	0.0	0.0	0.0
20	ENG	Feeder Repair by Weld Overlay	62568	Value Enhancing	May-09	Deferred	0.0		53.2		0.0	0.0	0.0	0.0	0.0	0.0
21		**Subtotal**					40.5				0.0	0.0	0.0	0.0	0.0	0.0
		PROJECTS NOT IN EB-2013-0321														
22	DN	Restore Emergency Service Water and Firewater Margins	31518	Sustaining	Dec-12	Sep-16	47.1	28.4			2.1	0.0	33.8	0.0	0.0	0.0
23	DN	Station Roofs Replacement	31524	Sustaining	Nov-12	Deferred	38.3	0.8			0.0	15.5	8.0	0.1	0.0	0.0
24	DN	Powerhouse Water Air Conditioning Units Replacement	31532	Sustaining	Oct-12	Dec-19	20.0	11.3			0.0	4.8	3.8	3.0	5.2	0.2
25	DN	Water Treatment Plant Replacement	31535	Sustaining	Oct-12	Deferred	57.8	5.2			0.0	0.0	0.0	49.9	0.5	0.0
26	DN	Transformer Multi-Gas Analyzer Installation	31542	Sustaining	Oct-12	Mar-18	22.7		22.7		6.0	3.5	1.6	0.1	0.0	0.0
27	DN	Radiation Detection Equipment Obsolescence	31544	Sustaining	Jan-14	Dec-21	46.9	1.2			0.0	6.6	10.2	9.5	1.7	0.8
28	DN	Condenser Circulating Water and Low Pressure Service Water Travelling Screens Replacement	31552	Sustaining	May-13	Jun-18	37.6	27.5			10.6	8.4	7.2	0.1	0.0	0.0
29	DN	Shutdown Cooling Heat Exchanger Replacement	31710	Sustaining	Nov-12	May-19	56.1	38.8			15.8	9.9	14.3	0.9	0.0	0.0
30	DN	Neutron Over-Power & Ion Chamber Amplifier Replacement (Reactor Regulating System, Shutdown System 1 & Shutdown System 2)	31716	Sustaining	Jul-13	Jul-22	17.7	5.5			0.0	0.0	0.0	1.0	2.3	0.0
31	DN	Zebra Mussel Mitigation Improvements	38948	Sustaining	Nov-12	Jul-16	21.5		21.5		18.9	1.0	0.0	0.0	0.0	0.0
32	DN	Holt Road Interchange Upgrade	73706	Value Enhancing	Nov-13	Dec-16	28.6		31.0		22.4	0.0	0.0	0.0	0.0	0.0
33	DN	OH180 Aging Management Hardware Installation	80022	Sustaining	Dec-14	Dec-22	47.2	1.4			0.0	0.0	7.9	5.7	5.5	5.6
34	DN	Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management	80078	Regulatory	Nov-15	Jun-25	47.3	1.7			0.0	0.0	0.0	0.0	1.6	6.0
35	DN	Generator Stator Core Spare	80111	Sustaining	Sep-15	Jul-19	35.0		35.0		0.0	0.0	0.0	32.0	0.0	0.0
36	DN	Vault Cooling Coil Replacement	82816	Regulatory	Dec-15	Sep-20	26.3	11.9			6.9	2.4	1.3	3.8	2.9	0.0
37	DN	Primary Heat Transport Pump Motor Replacement/Overhaul[7]	73566 80144	Sustaining	May-15	Dec-22	129.5	53.8			14.8	11.0	13.0	17.0	19.2	0.0
38	PN	Pickering B Fuel Handling Reliability Modifications	40976	Sustaining	Aug-12	Jul-17	37.3	30.9			11.5	7.9	4.2	0.0	0.0	0.0
39	PN	Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	41027	Regulatory	Oct-12	Jun-17	46.3	5.8			7.3	22.5	0.0	0.0	0.0	0.0
40	PN	Machine Delivered Scrape	66600	Value Enhancing	Feb-14	May-17	24.9	14.1	0.0	0.0	18.9	1.5	0.0	0.0	0.0	0.0
41		**Subtotal**					788.0				135.1	95.0	105.3	123.1	38.9	12.6
42		**Total**									330.2	146.5	122.2	134.3	44.9	24.6
		DIVISION TOTALS:														
43		**Darlington**									250.2	101.5	117.5	134.3	44.9	24.6
44		**Pickering**									79.4	45.0	4.7	0.0	0.0	0.0
45		**Nuclear Support Divisions**									0.5	0.0	0.0	0.0	0.0	0.0
46		**Total**									330.2	146.5	122.2	134.3	44.9	24.6

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2013-0321 or subsequent).
2 Total Project Cost reflects BCS amounts, with the exception of Completed/Deferred/Cancelled Projects (for which actual costs are shown).
3 Projects from Ex. D2-2-1 Table 7 in EB-2013-0321.
4 Projects from Ex. D2-1-3 Table 2 in EB-2013-0321.
5 Projects 31508, 49158 and 49299 are combined in a single Business Case Summary.
6 Projects 41023 and 49247 are combined in a single Business Case Summary. Project 49247 is from Ex. D2-1-3 Table 2 in EB-2013-0321
7 Projects 73566 and 80144 are combined in a single Business Case Summary

Table 2d
Capital Project Listing - Nuclear Operations Facility Projects
Projects $5M - $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project Number	Category	Project Description	Start Date	Final In-Service Date	Total Project Cost[2] ($M)	In-Service 2016 ($M)	In-Service 2017 ($M)	In-Service 2018 ($M)	In-Service 2019 ($M)	In-Service 2020 ($M)	In-Service 2021 ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		PROJECTS NOT IN EB-2013-0321												
45	DN	DN Dryer PLC Replacement	31420	Sustaining	Replace obsolete programmable logic controllers.	Feb-14	Mar-22	12.2	0.0	0.0	2.7	0.0	2.6	1.1
46	DN	DN Containment Button-up Activity Monitors Replacement	31432	Regulatory	Replace aging and obsolete radioactivity monitors used to button up the Negative Pressure Containment System on high activity.	Nov-13	Oct-19	8.0	0.0	1.2	1.8	2.8	0.8	0.0
47	DN	DN Computer Upgrade for HWMS (TRF/SUP)	31436	Sustaining	Upgrade obsolete Heavy Water Management System computers that control Tritium Removal Facility and Station Upgrader operations.	Oct-12	Feb-16	5.9	3.7	0.0	0.0	0.0	0.0	0.0
48	DN	DN Replacement of Obsolete Online Chemistry Analysers	31520	Sustaining	Replace obsolete online chemistry analysers	Oct-12	Nov-17	10.6	4.3	4.3	0.0	0.0	0.0	0.0
49	DN	DN RRS Logic Module Redesign	31534	Sustaining	Redesign the Regulator Regulating System logic modules to address spurious rod movements as well as addressing obsolescence of current modules.	Dec-13	May-26	9.9	0.0	0.0	0.0	0.0	0.0	5.3
50	DN	DN Feedwater Chemistry Control Improvements	31548	Sustaining	Install improved feedwater chemistry monitoring and connections for portable filtration.	Nov-13	Nov-22	10.3	0.0	2.2	1.8	2.1	0.0	0.0
51	DN	DN Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	32202	Regulatory	Provide capability to respond to Beyond Design Basis Events following the events at Fukushima Daiichi Nuclear Power Plant	Sep-11	Dec-17	28.0	6.9	7.6	0.1	0.0	0.0	0.0
52	DN	DN EPG Power Turbine Capital Spare	36004	Regulatory	Purchase a spare Emergency Power Generator power turbine to mitigate risk of engine failure.	May-13	Mar-17	8.1	0.0	4.5	0.0	0.0	0.0	0.0
53	DN	DN CSA Sewage Line and Sump Emergency Connections	38466	Sustaining	Replace corroded and degraded sewage piping from Central Services Area and add emergency connections to allow sewage truck to empty sump in emergencies.	Jul-13	Dec-17	7.9	0.0	6.4	0.1	0.0	0.0	0.0
54	DN	DN ESW Pipe and Component Replacement	73397	Sustaining	Replacement of degraded Emergency Service Water piping, valves and tanks during the 2015 Vacuum Building Outage.	Feb-14	Sep-15	6.7	0.3	0.0	0.0	0.0	0.0	0.0
55	DN	DN Large Steam Generator LCV Replacement	80023	Sustaining	Install new large Steam Generator level control valve actuators, valve trims and positioners to address operational and maintenance issues with current valves.	Jan-15	Oct-22	16.3	0.0	0.0	2.7	2.5	2.6	0.0
56	DN	DN R22 Refrigerant ACU Replacement	80036	Regulatory	Replace 51 air conditioning/dehumidifying units containing refrigerant R22 with units using approved non-ozone depleting refrigerant.	Jan-16	Oct-21	14.9	0.0	0.0	3.9	4.1	3.8	0.0
57	DN	DN Feeder Scanner Replacement (CMFA)	80070	Sustaining	Replace permanent feeder scanner equipment with portable system that can be setup outside of containment prior to use.	May-14	Mar-19	8.0	0.0	1.8	1.8	3.4	0.0	0.0
58	DN	DN FHA and FSSA Modifications	80151	Regulatory	Implement modifications required for compliance to Canadian Standards Association N293-07 Fire Protection for Nuclear Power Plants identified in the updated Fire Hazard Assessment and Fire Safe Shutdown Analysis prepared during the Integrated Safety Review and committed in the Integrated Implementation Plan.	Nov-15	Jan-19	6.8	0.0	0.0	0.5	4.7	0.0	0.0
59	DN	DN Irradiated Fuel Discharge Mechanism Major Component Replacement	82841	Sustaining	Replace the shuttle cylinders and other major components of the Irradiated Fuel Discharge system which are approaching end of design life.	Nov-15	Dec-22	5.9	0.0	0.0	0.0	0.0	0.0	5.2
		Table continues on Ex. D2-1-3 Table 2e												

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

COSTS OF ENVIRONMENTAL ASSESSMENT FOLLOW-UP STUDIES

In its decision in EB-2013-0321, the OEB required OPG to file at its next proceeding updates of actual costs of Environmental Assessment ("EA") follow-up studies.[1] Actual costs related to the environmental studies, monitoring and adaptive management projects required by the Darlington Refurbishment Program EA and follow-up program are provided in Chart A-1 below. There are no adaptive management programs at this stage of the program. They will be developed, if needed, based on the results of initial monitoring studies. It is important to note that these costs are not all for DRP and that these do not reflect all EA costs for the DRP.

Chart A-1

Actual Costs of EA Follow-up Studies

Project Work Package Description		Actual Spent		
		2013	2014	2015
EA Follow-up Studies	Effluent Characterization	$0 K	$5 K	$7 K
	Fisheries Authorization	$0 K	$25 K	$0 K
	Entrainment Study	$0 K	$25 K	$198 K
	Benthic Invertebrate Community Study	$0 K	$25 K	$0 K
	Thermal Monitoring	$0 K	$20 K	$0 K
	Stormwater Control Study	$0 K	$0 K	$0 K
Environmental Monitoring Studies	Groundwater monitoring, sampling and analysis for chemical waste, groundwater wells	$170 K	$270 K	$370 K
	Biodiversity studies and monitoring	$40 K	$50 K	$50 K
	Chemistry laboratory cost for supporting environmental monitoring[2]	$3.1 M	$3.1 M	$3.2 M
	Stack and filter testing emission verification	$285 K	$190 K	$160 K
	Radiological Environmental Monitoring Program	$150 K	$260 K	$160 K
Adaptive Management Projects		$0 K	$0 K	$0 K

[1] EB-2013-0321, Decision with Reasons, November 20, 2014, p. 55.

[2] Chemistry laboratory costs include both environmental monitoring costs and station chemistry control costs. The value in the chart represents 50 per cent of chemistry laboratory costs as an approximation of the costs associated with environmental monitoring.

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Records File Information:
Final Security Classification of the completed form is determined below
00120.3 - P For Nuclear
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OPG-FORM-0077-R001*

Project Over-Variance Approval

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

This form should not be used for over-variances in excess of 20% of cost or schedule or both. Submit this form with attachment of the latest approved Business Case Summary.

Part A: Project Information

Project #:	16-25619	Title:	Operations Support Building Refurbishment		
Phase:	Execution	Class:	Capital	Records File:	D-BCS-28110-10004

	LTD	2015	2016	2017	Future	Total
Current Approval	28,233k	23,949k	848k			53,030k
Amount Requested	-	8,773k	890k			9,663k
New Total Release	28,233k	32,722k	1,738k			62,693k

Brief Description of the Project:

The OSB was constructed in 1982 with the third floor added in 1988. It is an important facility that houses technical services essential to the business operations of Darlington (DNGS). These technical services include: site security systems, site information technology (IT) and telephone network hubs, quality assurance vault, station domestic water piping and radiological public domain access to the powerhouse via the bridge. A unique requirement for this project is to maintain the operation of these technical services amidst construction activities.

The facility has the capacity to house approximately 375 Darlington employees who provide daily operations, maintenance and administrative support to station and control room staff. An assessment by an external engineering firm determined that many of the existing building systems were expected to be life expired by 2015. These systems needed to be replaced to maintain a healthy environment for employees and essential technical services, as well as to minimize corrective maintenance on expired systems. The refurbished building is designed with energy efficiency and occupancy comfort in mind.

Reason for Schedule Variance:

The project is currently scheduled to meet the Available for Service milestone of October 30, 2015 as committed to in the execution-full BCS. There is a risk that challenges during the commissioning phase of the project could threaten this milestone. This risk is being mitigated through the hiring of a commissioning agent to execute this work in an efficient manner.

Reason for Cost Variance:

The EPC contract value budgeted in the execution-full business case summary (BCS) was $37.7M. The contractor is now forecasting to spend a total of $51.8M, not including any additional discovery issues and challenges during commissioning not yet known by the project team (for which $1.5M in contingency is now being requested to cover).

Of the $14.4M contract cost variance, $11.7M is attributed to the EPC Contractor underestimating the effort required to complete the contract scope. OPG is required to pay these additional costs since the contract is cost reimbursable. The variance is summarized by the following issues:

1) The design subcontractor was required to complete revisions to the design packages due to incomplete details from the original documentation.
2) The procured equipment and construction work required to complete the design revisions has now increased significantly beyond budget due to the design packages being complex.
3) The contractor is behind schedule compared to their original plan as documented in the contract, which has resulted in additional contractor project management and engineering field support.

The remainder of the contract cost variance can be linked to a few contract scope changes, totalling $2.7M. These changes include:

1) Upgrade of motor control electrical distribution equipment
2) Additional cabling and hardware to support changes to IT and telephone requirements
3) Changes to furniture and building layout requirements as requested by building occupants

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Project Over-Variance Approval

4) Upgrades to the fire separation of civil structures that were previously hidden
5) Repairs to the exterior walk ways and soffits
6) Other minor architectural, mechanical, electrical changes

In the execution- full release, $2.6M of specific contingency was included to cover the above EPC contract issues including the discovery of unknowns as well as the under-estimation of effort required to complete a building refurbishment.

During construction the project has realized some other specific risks, requiring the partial use of the contingency from the execution-full BCS.

1) Discovery and planned remediation of mould: $0.4M increase to budget ($0.7M contingency specified in BCS)
2) Hiring of a commissioning agent to ensure an efficient building start-up, minimizing the impact of commissioning issues on the overall project: $0.1M increase to budget ($1.1M contingency specified in BCS)
    a. The remainder of the commissioning risk has not yet been realized as this process is just beginning.

The remaining risks with specific contingency allocated from the execution-full BCS have either not yet been realized or have been mitigated without the need for utilizing contingency funding.

The project has also required additional support from OPG engineering to provide oversight of the EPC contract design subcontractor as they completed the design revisions. This has resulted in an increase of $0.5M to the project budget.

The project is still developing a list of spare inventories that will need to be procured by OPG to operate and maintain this facility once the project is complete. An initial list is being reviewed by the operations and maintenance team to ensure only required spares are eventually purchased. A preliminary estimate of the spare inventory costs is $50k.

Options Considered to Mitigate Overruns:

The project team has been performing weekly reviews of the EPC contractor's project cost, schedule and risks to validate assumptions and to help overcome challenges. As an example, the project team reduced the impact on critical path created by the fire detection design package revisions by securing stakeholder concurrence to procure and install fire detection devices with minimal probability that the design would change.

The project has also been having frequent meetings and walk downs with the project sponsor and other stakeholders to seek early resolution of deficiencies that would otherwise delay eventual turnover of the building to the operations and maintenance team.

As the design and construction work has evolved, the OPG project team has continually reviewed the project scope and removed specific scope items where possible. This includes:

1) The simplification of internal governance documentation requirements to align with commercial building applications
2) Utilizing more cost effective ceiling tiles
3) The removal of exterior light distribution shelves around the perimeter of the office space

The hiring of the expert commissioning agent is expected to yield efficiencies in the commissioning process as well as reduce the impact of discovered challenges when energizing equipment.

The project actual costs to date include invoices submitted by the EPC contractor that are being disputed by OPG. As such, there is an opportunity to remove $1.0M from the project costs if OPG is successful with the disputes.

When the project removed the existing motor control centre equipment prior to their replacement, the existing circuit breakers and associated electrical equipment were transferred to the maintenance department as useful spares. This obsolete equipment has become costly for the nuclear station to have reverse engineered. This effort may not mitigate the project overruns directly however it is expected to yield overall savings to OPG.

Project Status:

At the time of execution-full business case summary approval in May 2014, the project had been completing demolition and procuring schedule critical equipment and materials. Since then, the project has progressed with significant procurement and construction work, including:

1) Procurement of all schedule critical equipment and materials
2) Installation of the new exterior curtain wall and roof membrane, leaving the building water tight
3) Mechanical, electrical, instrumentation and controls systems installation throughout the 1st, 2nd and 3rd floors

Project Over-Variance Approval

4) Elevator and associated controls are fully operational with all regulatory approvals received
5) Substantial completion of furniture installation on the 2nd and 3rd floors
6) The motor control centres have been replaced and are operational.
7) Major mechanical equipment and associated piping such as chillers, ventilation units, pumps located in the basement has been installed.
8) Routing of IT and telephone cabling throughout the building in progress
9) Fire sprinkler system pipe work installation completed on 1st, 2nd and 3rd floors
10) Kitchen/cafeteria architectural finishes and mounting of equipment is complete.
11) Overhead lighting on the 1st, 2nd and 3rd floors is operational
12) Heating, ventilation and air conditioning system flushing and equipment commissioning is in progress

The above work has progressed with a good safety and environmental record and has been completed with no impacts to the essential services located in the building, nor creating an impact to the nuclear station electrical and mechanical systems that the OSB systems depend on.

ONTARIO POWER GENERATION

Records File Information:
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Project Over-Variance Approval

Part B: Variance Detail				
k$	Current Approval	Amount Requested	Variance	Comments
OPG Project Management	4,298	3,627	(671)	Project management oversight on the project has required less effort than initially planned.
OPG Engineering (Including Design)	662	1,162	500	Revisions to the designs based on field challenges during construction have required an increase in the OPG design oversight.
OPG Procured Non-Fixed Assets (IT/Telephone)	895	1,000	105	Building occupants have identified additional IT equipment to be purchased.
OPG IT/Telephone Service Provider Installation Costs	470	500	30	Building occupants have identified additional IT equipment to be installed.
Design Contract(s)	596	596	0	All standalone design contracts have been completed.
Construction Contract(s)	0	0	0	All construction work is being completed as part of the EPC contract.
EPC Contract(s)	40,278	49,119	8,841	As discussed in the cost variance section.
Consultants	0	0	0	
EPC Procured Non-Fixed Assets (Furniture)	2,500	2,712	212	Building occupants have identified changes to the ground floor layout that requires some additional furniture to be procured. There were also minor changes to the design requiring changes to the furniture procured.
Interest	3,331	2,477	(854)	The amount of interest required was overestimated in the previous release. The updated interest from now until project completion is based on most recent cash flows.
Subtotal	53,030	61,193	8,163	
Contingency	0	1,500	1,500	Contingency is required for estimate inaccuracy and for the possible realization of unknowns, particularly during the commissioning phase.
Total	53,030	62,693	9,663	
Removal Costs Included	2,540	983	(1557)	The amount requested is based on the actual spent; no further removal costs planned.

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ONTARIO POWER GENERATION

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Project Over-Variance Approval

Part C: Review/Approvals			
	Signature	Comments	Date
Recommended by: Glenn Jager Chief Nuclear Officer Project Sponsor			August 7, 2015
Finance Approval: Beth Summers Chief Financial Officer		• REQUEST FOLLOW-UP TO UNDERSTAND ROOT CAUSES FOR FINAL VARIANCE	August 7, 2015.
Approved by: Tom Mitchell President and CEO Per OAR Element 1.1			AUG 8 2015

• This is poor performance. A C2 SRR is to be issued and the results of the review to be presented to the CWO. In addition Art Rob is to present to the CWO where performance warrant follow-up is required with OPG and vendor staff ~~responsible~~. At this point there is little option but to approve the costs.

Agree

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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.

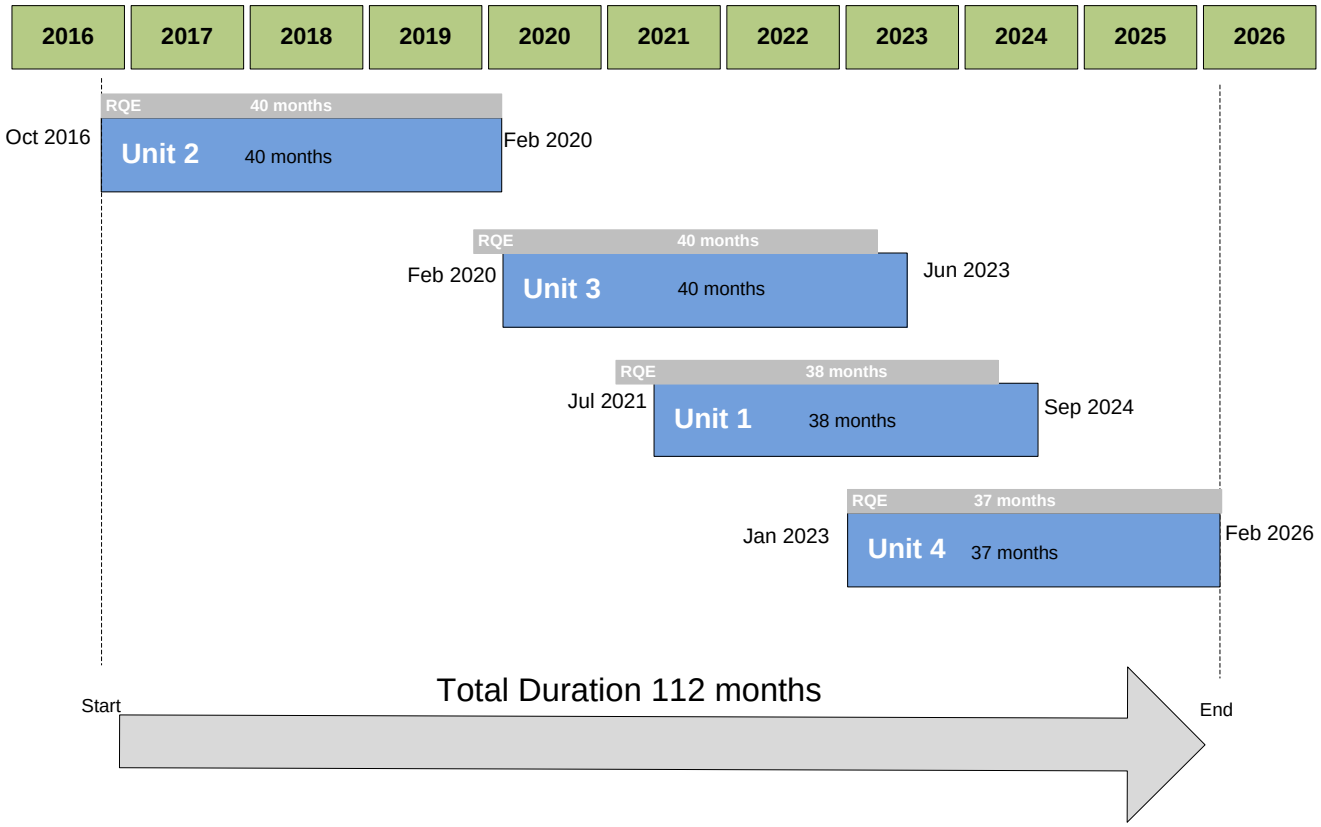
The overall 4-unit high confidence schedule duration remains at 112 months per Table 1 below:

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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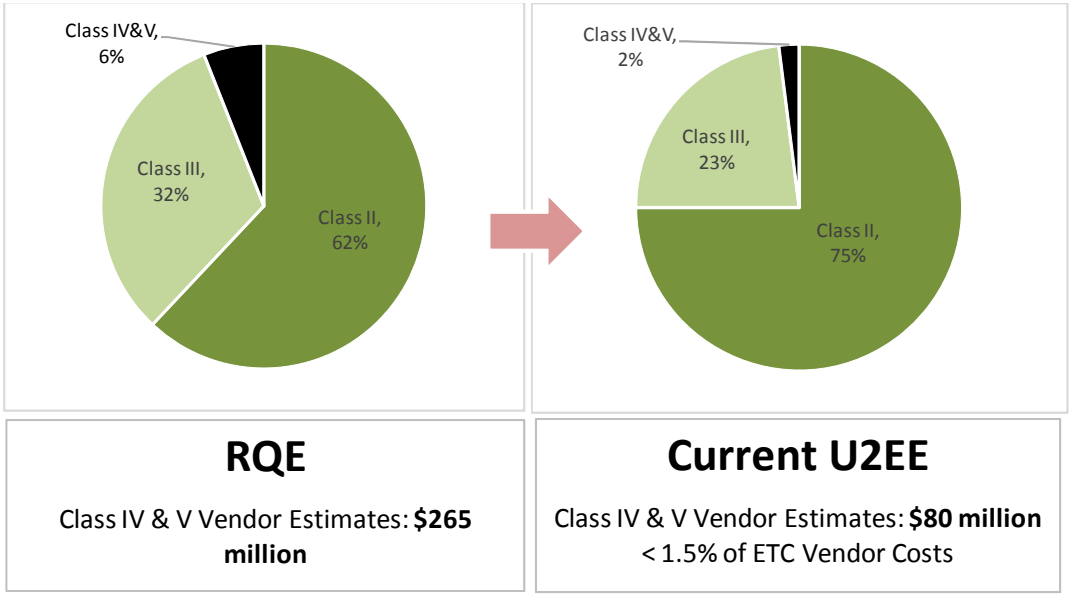
Figure B: Estimate Classification Summary



(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

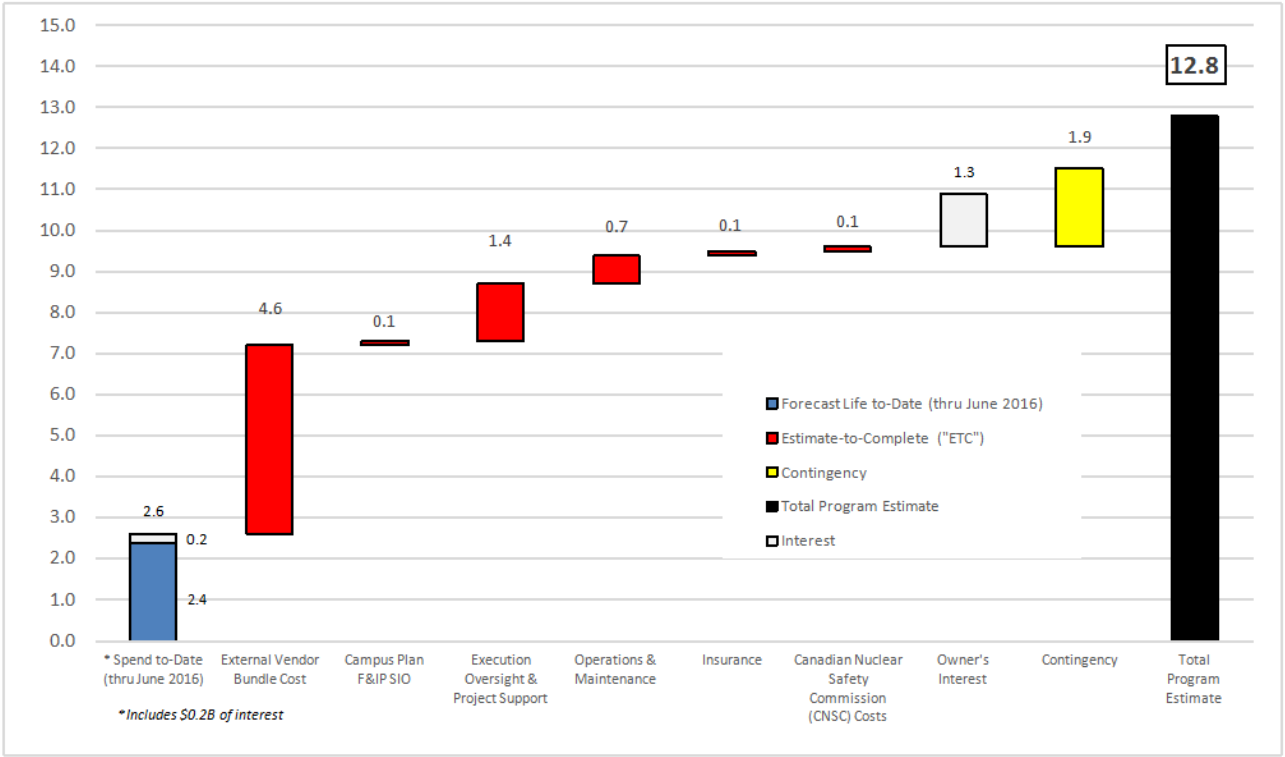
2009 Estimate	2015 RQE High Confidence Estimate	Current High Confidence Estimate
$14.0 Billion(1,2)	$12.8 Billion(2)	**$12.8 Billion(2)**

(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.

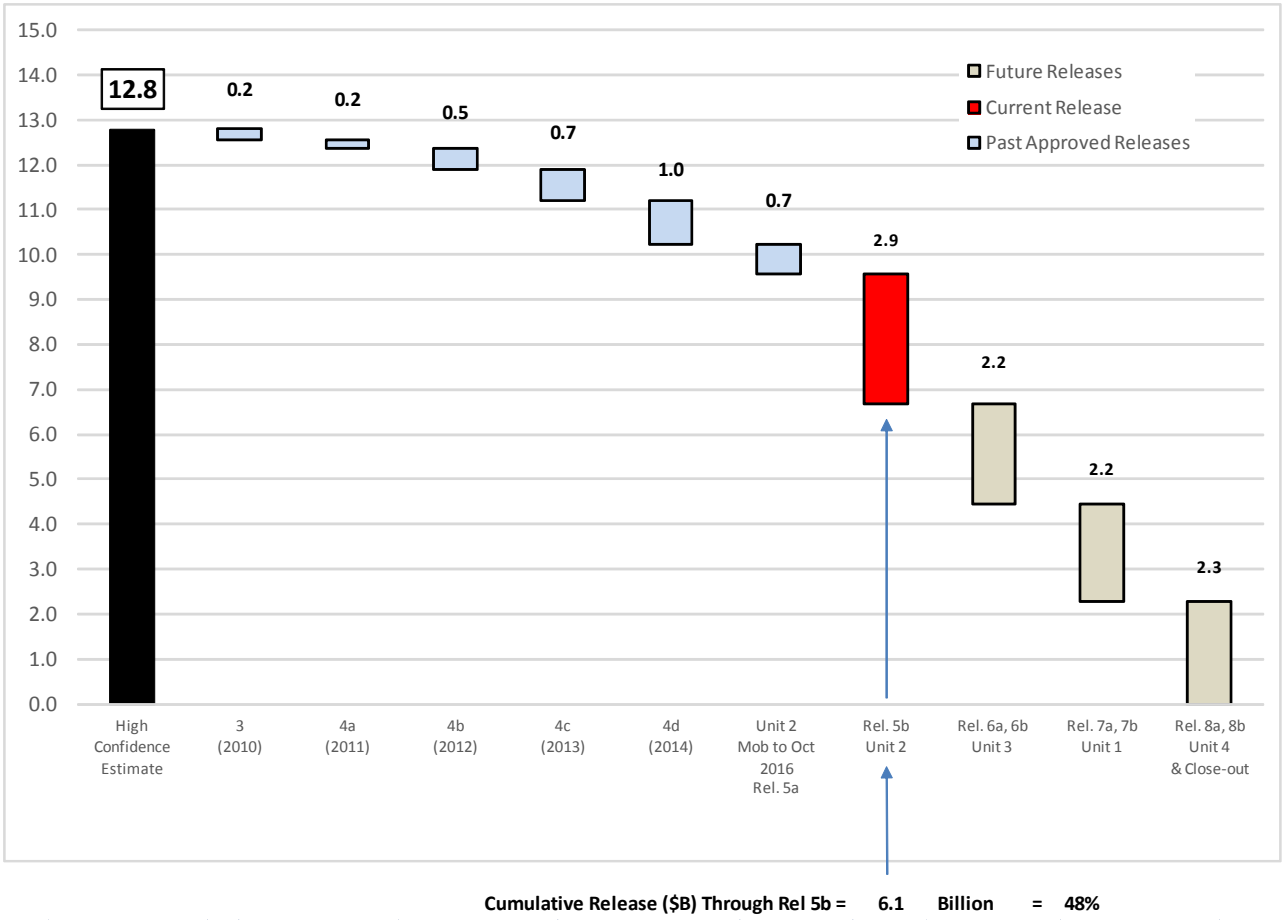
Table 5: Program Funding Releases

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.

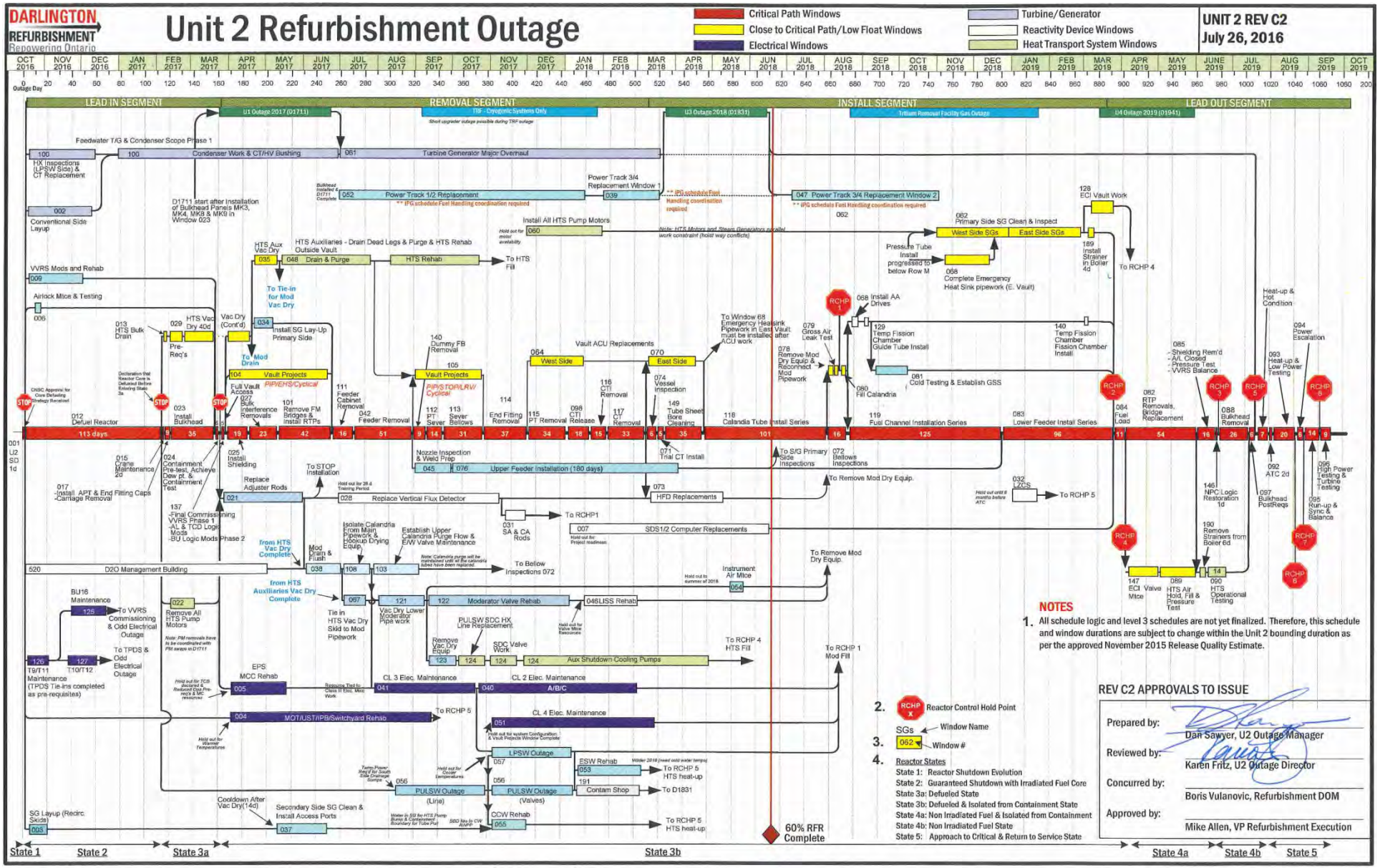
Recommended by:	**Approved for submission to the Board of Directors by:**
_____	_____
Dietmar Reiner	Jeff Lyash
Senior Vice President, Nuclear Projects	President and CEO

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

APPENDIX 1: UNIT 2 LEVEL 1 SCHEDULE



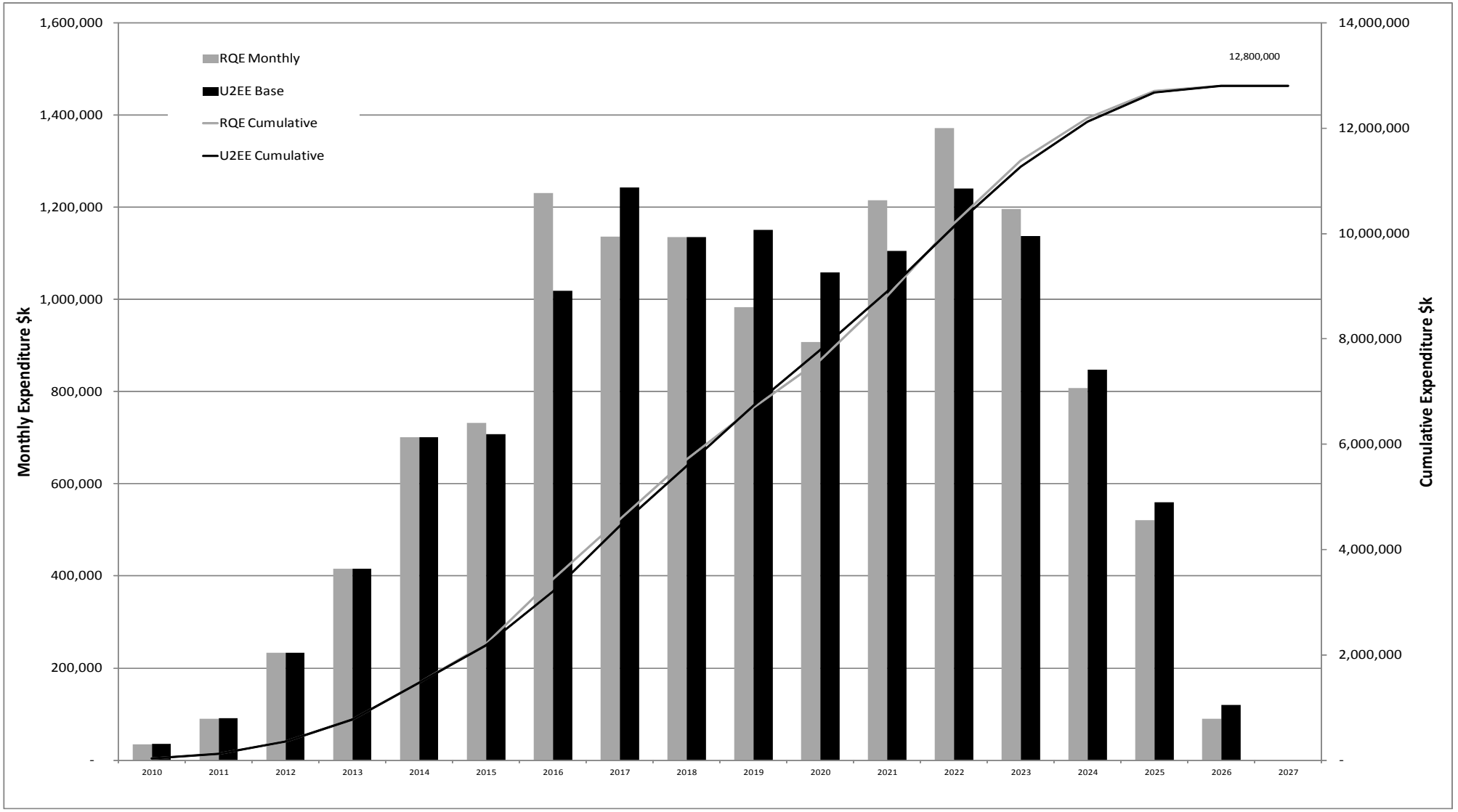
APPENDIX 2A: 4-UNIT COST SUMMARY

#	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

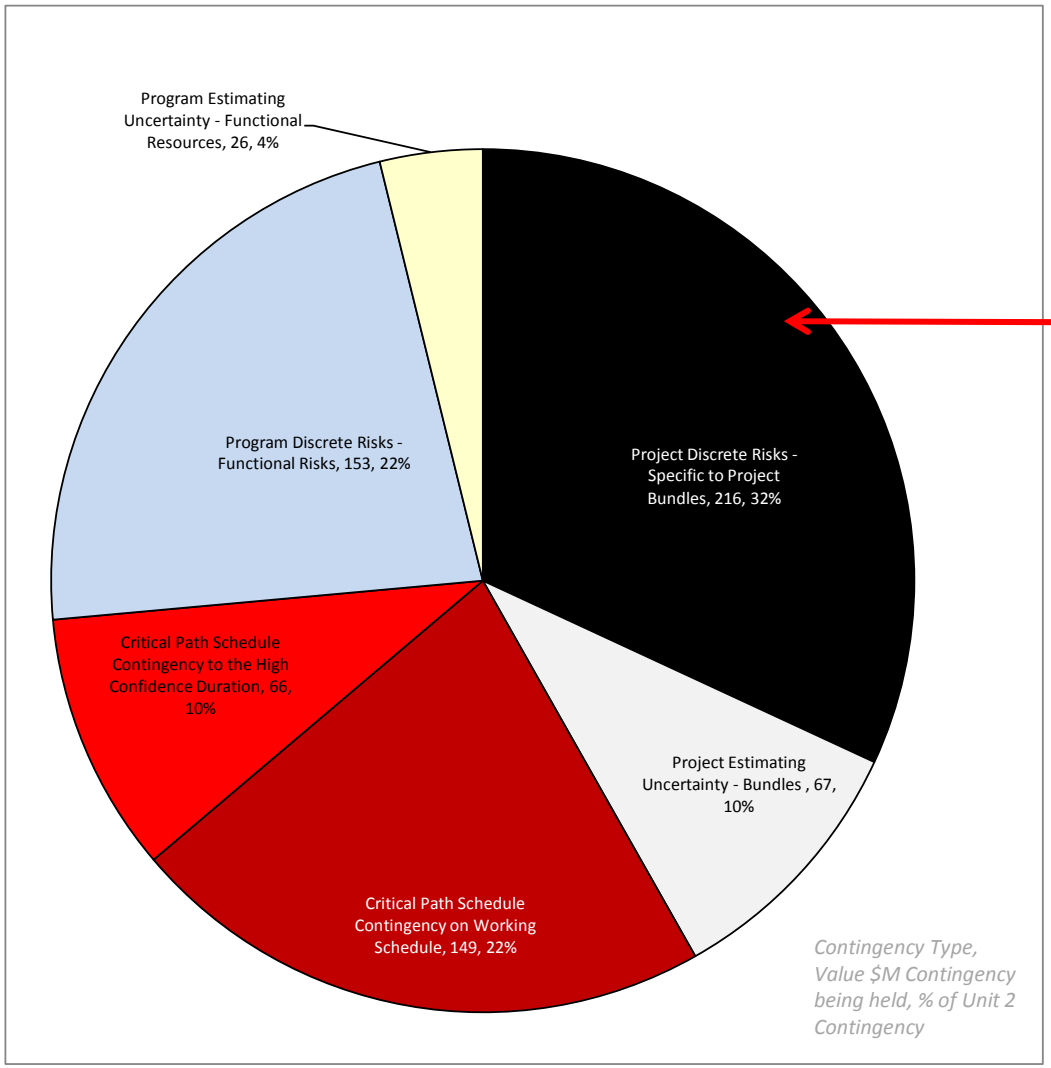
#	Division	RQE	Current U2EE	Variance from RQE	%
1	NR - Retubing & Feeder Replacement	1,143,965	1,148,041	4,077	0%
2	NR - Turbine Generator	226,164	228,012	1,849	1%
3	NR - Balance of Plant	165,731	186,299	20,568	12%
4	NR - Fuel Handling	21,498	16,448	(5,050)	-23%
5	NR - Defueling	31,544	35,978	4,434	14%
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

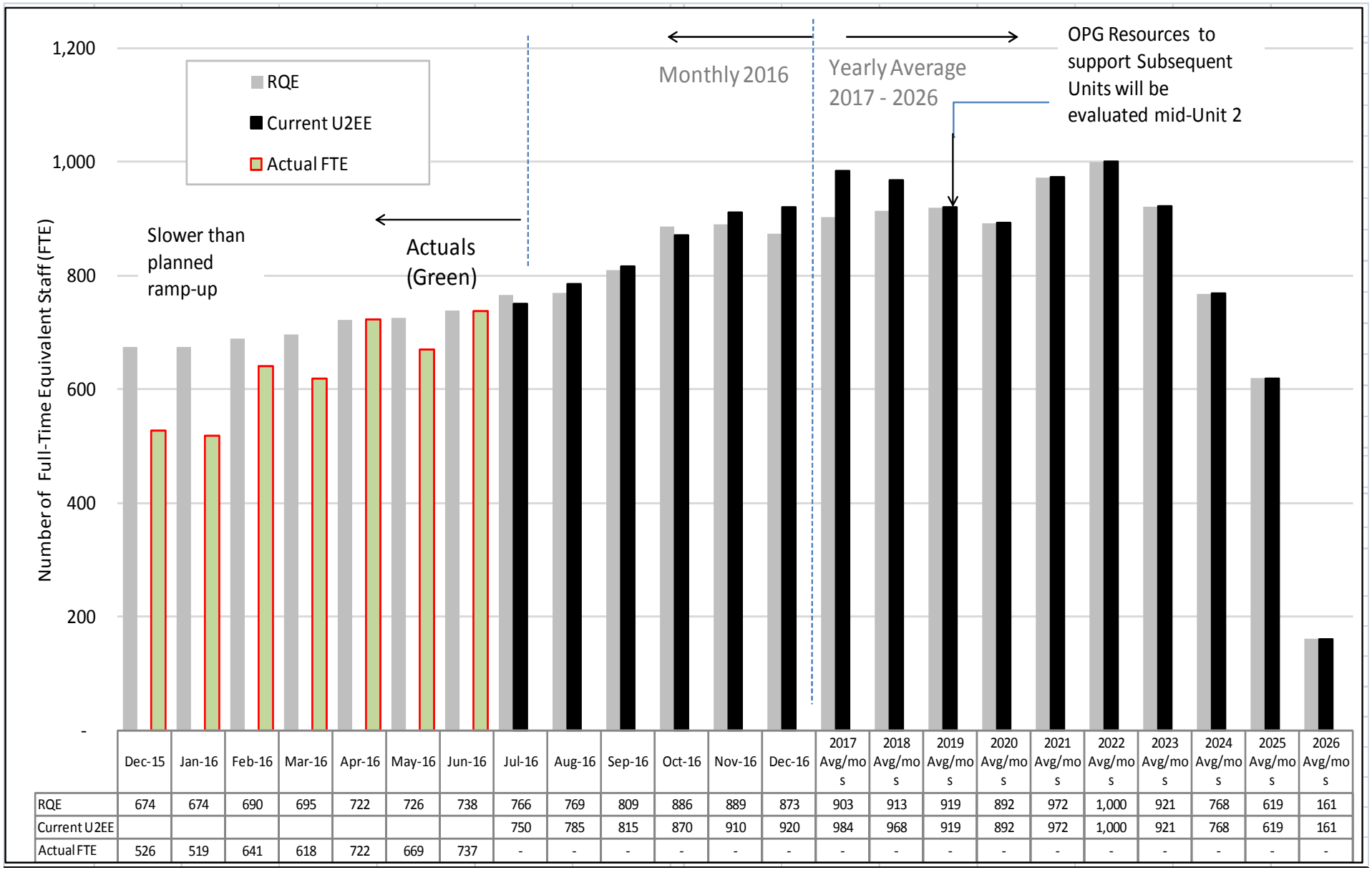


Unit 2 Discrete Top Risks by $ Value

Bucket	Bundle / Functional	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

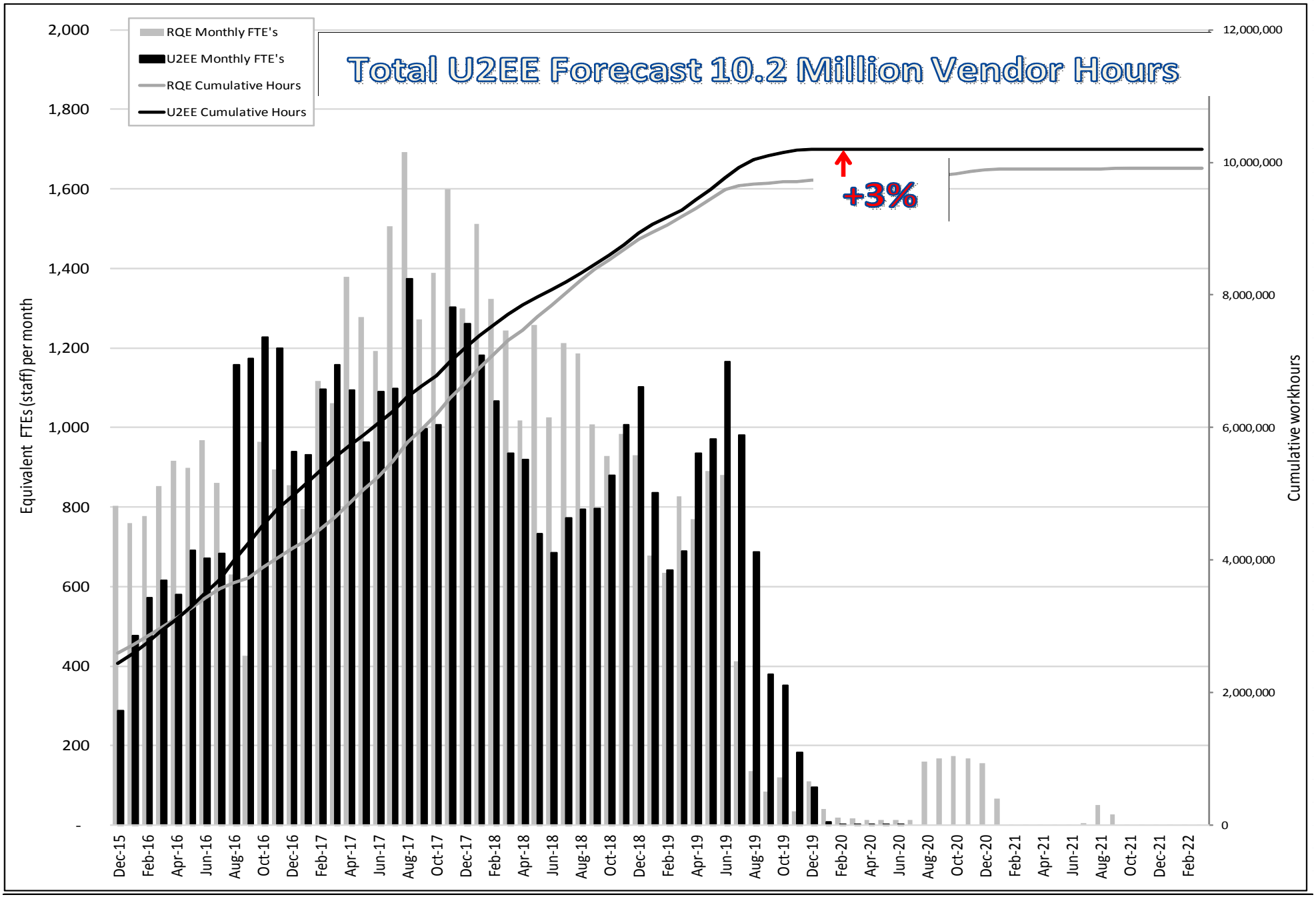
APPENDIX 5A: RESOURCE ANALYSIS – OPG RESOURCES: U2EE vs. RQE

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**

Headcount Reductions

The additional reduction in headcount from ongoing operations of 1,000 over the 2013-2015 period will be achieved by aggressively pursuing efficiencies and restructuring

- Nuclear headcount decreases by ~425 or 8% over the 2013-2015 period through various efficiency initiatives, including the amalgamation of the Pickering A and B stations

[redacted]

	Actual	Budget *	Business Plan *	
	2012	2013	2014	2015
Nuclear Operations	5,510	5,325	5,195	5,083
Nuclear Projects	728	713	701	698
Hydro/Thermal Operations	[redacted]			
CO&E	176	176	165	153
Total Operations	[redacted]			
BAS	1,083	1,039	980	924
Finance	382	361	335	308
People & Culture	598	623	596	573
Corporate Office	158	156	149	144
Total Support Services	2,221	2,179	2,060	1,949
Ongoing Operations	[redacted]			
Darlington Refurb	180	247	266	276
Nuclear New Build	33	23	21	21
Total OPG	[redacted]			

*Headcount numbers are adjusted for organizational changes

- Support Services headcount decreases by ~275 or 12%, over the 2013-2015 period through Business Transformation initiatives. Under a centre-led organizational structure, Support Services now includes certain operational functions such as: Business and Administrative Services includes Supply Chain and warehousing operations; Finance includes Nuclear Oversight; and People and Culture includes the Nuclear Training division.
- Darlington refurbishment headcount increases over the period as engineering, operations and oversight staff join the project organization during the detailed planning stage
- Nuclear new build headcount remains steady until such time as a decision is made on the future of the project. The plan currently does not assume execution of this project, hence there is no increase in headcount.

Regular Headcount by Business Unit*	Actual 2013	Actual 2014	Actual 2015	Business Plan 2016	Business Plan 2017	Business Plan 2018	Projection 2019	Projection 2020	Projection 2021
Nuclear Operations	5,668	5,491	5,297	5,400	5,448	5,432	5,367	5,267	5,202
Nuclear Projects	302	274	253	284	277	277	267	257	257
Hydro Thermal Operations	[redacted]								
Commercial Operations & Environment	169	180	165	180	175	174	166	165	165
[redacted]	[redacted]								
Total Operations	**7,984**	**7,501**	**7,171**	[redacted]					
Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain)	1,010	947	870	892	869	859	852	839	839
Finance	307	273	266	278	268	261	255	249	249
Assurance (incl. Nuclear Oversight)	58	57	53	57	57	57	57	57	56
People & Culture (incl. Centralized Training)	580	576	531	557	563	556	561	557	551
Corporate Office	91	86	77	84	83	83	82	81	81
Corporate Business Development	55	49	42	48	48	48	48	48	48
Total Support Services	**2,101**	**1,988**	**1,839**	**1,916**	**1,888**	**1,864**	**1,855**	**1,831**	**1,824**
Total Ongoing Operations	**10,085**	**9,489**	**9,010**	[redacted]					
Darlington Refurbishment Project	181	189	237	501	512	520	545	524	519
Total Regular Headcount	**10,266**	**9,678**	**9,247**	[redacted]					

* As reported/projected at each year-end; not restated for subsequent budget transfers between organizations

UNDERTAKING JT1.2

Undertaking

TO ADVISE WHAT OPG IS OVERSEEING WITHIN THE PROJECT AND TO BREAK DOWN COSTS ASSOCIATED WITH UNIT 2

Response

OPG has interpreted the question to provide oversight costs consistent with the categories listed D2-2-8 Chart 3 for both the total RQE as well as Unit 2.

Oversight costs have been defined to include those costs associated with performing oversight of vendors who are executing work in the field. This includes direct oversight of project teams as performed for each project bundle, as well as indirect oversight of project execution which includes construction, safety, and quality oversight. Contract Management performing commercial oversight, Managed Systems Oversight performing assurance activities, Planning and Controls which performs project controls including estimating, cost management, change management, and reporting, and Work Control performing scheduling and day-to-day work management are also included in oversight.

The costs which have been excluded are not considered oversight, but are instead providing support to the executing organizations. For example:

- Operations and Maintenance functional costs are considered as support costs as these costs predominantly relate to the “custodian” role, controlling authority, as well as radiation protection services.
- Engineering costs are predominantly to support design and return-to-service activities.

DRP OPG Oversight costs represent costs across the entire program (2010 – 2026), whereas Unit 2 OPG Oversight costs are related to Unit 2 including during the definition phase (2010 – 2020).

D2-2-8 Chart 3 - DRP RQE Breakdown ($M)

#	Bundle / Category	DRP OPG Oversight	U2 OPG Oversight
1	Retube & Feeder Replacement	167	106
2	Turbine Generators	41	22
3	Balance of Plant	183	98
4	Fuel Handling/Defueling	49	32
5	Steam Generators	13	6
6	**Subtotal Major Work Bundles**	**452**	**264**
7	Facility and Infrastructure Projects	-	-
8	Safety Improvement Opportunities	-	-
9	**Subtotal F&IP / SIO**	**-**	**-**
10	Project Execution	180	88
11	Contract Management	52	25
12	Engineering	-	-
13	Managed Systems Oversight	41	25
14	Planning & Controls	95	65
15	Nuclear Safety	-	-
16	Program Fees & Other Support	-	-
17	Supply Chain	-	-
18	Work Control	80	30
19	Ops & Mtce	-	-
20	Early Release 3	-	-
21	Early Release 4	-	-
22	**Subtotal OPG Functions**	**447**	**233**
23	Contingency	-	-
24	**Subtotal before Escalation**	**899**	**497**
25	Interest	**-**	**-**
26	Escalation	**-**	**-**
27	**Subtotal Interest & Escalation**	**-**	**-**
28	**Total Oversight**	**899**	**497**

So there are layers of oversight on top of -- even though that project managers have the authority to do small change, there are layers of oversight to oversee that.

MR. RUBENSTEIN: If I can ask you to turn to Staff 61, Part (b). Part (b) talks about, you've -- already a $1 million disincentive payment was paid to OPG, and I was wondering if you could just help me understand what happened, and if you can help me understand this part of -- Part (b) of this response.

MR. ROSE: Mr. Reiner and I will probably tag-team on this one. In essence the joint venture had a number of milestones that were authorized when we set the definition phase contract. Those milestones included things like completion of what we call construction work packages, detailed work packages and how they were going to execute the work, procurement of materials and goods, et cetera.

In the final reviews, some of those milestones representing less than 2 percent, approximately 18 million, were outstanding. We are not going to meet the definition-phase milestone, so in that negotiation as to what the milestones would be, we set a new set of milestones and received a million dollars lump-sum disincentive payment for that, for the shift of those dates.

MR. RUBENSTEIN: I am going to ask you to turn to 4.3 SEC 32. So in Part (b), just backing up a step, my understanding was it was identified by Burns & McDonald and Modus that there was an opportunity for about $700 million in potential savings in the 3D cost estimate, and then

ultimately that didn't materialize in the next version.

And we had asked you in Part (b), can you explain that, and essentially you say, There was a list of opportunities that were -- or at least as I am reading this -- were quantified at $700 million. We thought about it and we couldn't -- just couldn't get to that.

Can you help me understand why some of these opportunities were not realized, why would not be able to -- achieved at -- in a high level at...

MR. ROSE: So just the first thing, one clarification: It was in Modus's report, but it was OPG working with the joint venture that identified the opportunities for improvements. We had received their estimate. Of course in our reviews we look for opportunities.

One of the reasons why we couldn't apply the improvement opportunity in the current estimate is that some of them required technical evaluations, so is there is one opportunity to not do tube-sheet cleaning. It's something that all other refurbishments have done, but we are evaluating whether or not that actual tube-sheet cleaning is truly providing any value, if it's something that we can just not do. In order to apply that opportunity, we have to do some technical evaluations, et cetera.

So for unit 2 we have assumed and are planning to do that work, but we have ongoing initiatives underway to look through, are there any other opportunities like that that we could not do certain things that would ultimately lower

the cost and schedule of the project.

But the current plan for unit 2 is based on the experiences of the fact that that work was done on previous refurbishments.

MR. RUBENSTEIN: So ultimately there are still -- of the list of things that you could potentially see savings, you actually -- those may actually occur. You haven't foreclosed this. Here you are saying you are doing some technical evaluation about the cleaning, the tube cleaning.

MR. ROSE: There is always opportunity for us to look for opportunities to save costs and schedule. We do that actively, and if we can there will be a change order to the R&FR schedule in this case, or target price in this case, that would adjust the in-service amount.

MR. RUBENSTEIN: I know you are always looking for opportunities, but of the specific ones that we talked -- that were identified by you in the JV, just of that amount.

MR. REINER: So there are -- just to elaborate on what Mr. Rose was saying, there are a couple of specific opportunities that we are just in process of establishing a team that we will pursue with a mind to incorporating them into the second unit refurbishment. And they deal -- they deal primarily with the technical aspects of how the retube portion of the project gets executed.

And they have -- these opportunities have the potential to take significant amounts of time out of the schedule. But they do require some research and development type work. They require new tooling to be

developed. That tooling needs to be tested on our mock-up, and then we'd have to adjust procedures and execution processes to actually incorporate them into the project.

So we are going to pursue a couple of those that look quite material. There are others that are already incorporated. For example, in the retube waste-processing space, we have made a change in how we are going to process waste that resulted in a significant reduction in waste containers and time duration associated with processing waste.

We also went after an opportunity that reduced significantly the risk in bulkhead installation by looking at a new tool and a new method for installing the bulkhead relative to what was previously done during construction days.

So some are factored into our plan, but there are a short set of discrete areas that we are going to pursue to see if we can actually make them work and therefore adjust the schedule.

MR. RUBENSTEIN: Thank you very much.

If I can ask you to turn to 4.3 SEC 16, attachment 1. This is the turbine generator equipment sole source justification report document.

MR. KEIZER: Sorry, was that one-six or six-zero?

MR. RUBENSTEIN: 4.3, SEC 16, attachment 1.

MR. KEIZER: 16. Thank you.

MR. RUBENSTEIN: We may not even need to bring it up. The document references a number of exhibits, and I was

Public Reporting on the DRP

Category	Measure
Progress	• Key Achievements • % Complete
Safety	• All Injury Rate
Quality	• Quality Compliance (metrics to be determined)
Cost	• Cost Performance Index • Life-to-date cost • Forecast to Complete • Estimate at Complete
Schedule	• Schedule Performance Index • Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates

8.0 OVERSIGHT

OPG has developed and implemented an assurance plan that is comprised of several layers of oversight, including from Program staff, external contractors, Program leadership, enterprise leadership and external advisors. The plan ensures appropriate oversight during the execution readiness and Execution Phase of the Program, with a focus on key risk areas. Specifically, oversight will help to ensure that the DRP meets safety, quality, cost and schedule expectations, that issues are identified and resolved expeditiously, and that transparent and accurate information flows up to the Board of Directors.

OPG's oversight and assurance processes are supported by transparent, timely and accurate information flows to support decision making at appropriate levels within the organization. Key aspects of OPG's DRP oversight include:

- *project-specific oversight processes and practices* based on risk management, operating experience, contract requirements, scope of work and reviews of contractor performance by each of the Project Management Teams, as well as by the Project Execution Support Function (see: section 3.2.1 of Ex. D2-2-2);
- *oversight of the Executing Organization* (see Ex. D2-2-2, Figure 1) by the DRP leadership team and by Program functions, including the:

Chart 1: Nuclear Deficiency for 2017 - 2021 Period

Line No		($M) 2017	($M) 2018	($M) 2019	($M) 2020	($M) 2021	Reference
1	**EB-2013-0321 Average Approved 2014 & 2015 Revenue Requirement**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	Note 1a
2	Revenue at EB-2013-0321 Payment Amount ($59.29/MWh)	**2,258.9**	**2,280.9**	**2,313.9**	**2,214.8**	**2,097.9**	Note 2a
3	Lower Production (line 1 - line 2)	**575.2**	**553.1**	**520.2**	**619.2**	**736.1**	
	Changes in Revenue Requirement:						
4	Darlington Refurbishment	75.7	26.9	(9.1)	528.8	559.4	Note 3a
5	Pickering Extended Operations Enabling Costs	25.6	55.3	107.1	104.3	0.0	Ex. F2-2-3 Chart 2
6	Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities	31.8	36.2	42.2	129.7	132.2	Ex. C2-1-1 Table 5, line 18
7	Impact of Changes in Nuclear Liabilities Reflecting 2017 ONFA Reference Plan	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)	Ex. N1-1-1 Chart 3.2.1 line 8
8	Remaining Depreciation and Amortization Expense *(other than lines 4, 6 & 7)*	99.9	136.9	143.7	132.4	(141.7)	Note 4a
9	Outage OM&A Expenses *(other than line 5)*	75.8	59.8	29.9	12.2	11.8	Note 5a
10	Remaining/Other OM&A Expenses *(other than lines 4, 5, 6, & 7)*	81.8	103.5	164.4	182.2	194.6	Note 6a
11	Fuel Costs *(other than lines 6 & 7)*	(49.8)	(47.8)	(37.5)	(41.4)	(56.7)	Note 7a
12	Other	50.1	55.5	48.7	42.3	51.8	Note 8a
13	**Total Change in Revenue Requirement** (lines 4 through 12)	**367.8**	**393.5**	**485.8**	**1,005.8**	**624.4**	
14	**Total Revenue Deficiency** (line 3 + line 13)	**943.0**	**946.6**	**1,005.9**	**1,625.0**	**1,360.6**	

Notes

1a Ex. I1-1-1 Table 2, Line 11

OEB APPROVED		
2014	2015	AVERAGE
2,790.4	2,877.6	2,834.0

2a

REDUCED PRODUCTION	2017	2018	2019	2020	2021
Test Period Production (Ex. E2-1-1 Table 1, line 3, cols. (e) to (i)) **(TWh)**	38.1	38.5	39.0	37.4	35.4
Nuclear Base Payment Amount (EB-2013-0321 Payment Amount Order, App D, line 3) **($/MWh)**	$59.29	$59.29	$59.29	$59.29	$59.29
Forecast Revenue ($M)	2,258.9	2,280.9	2,313.9	2,214.8	2,097.9

Carlo analysis, there must have been a starting P amount so you would know how much contingency to get to the 50.

MR. ROSE: Our drive was that the base estimate was a P0, right, so that they didn't have any contingency built into it. But we ran the Monte Carlo to figure out how much contingency we needed to get to P50.

MR. RUBENSTEIN: So it's P0 is the --

MR. ROSE: That was our drive to the vendors, is to get the estimate, the base estimate, to a point where there was no risk-based information included in it, was -- don't forget with the R&FR we used our tooling to determine time it would take to do things, you know, as under assessment that everything worked as it did in the mock-up.

MS. GRICE: Okay, thank you.

I just -- I have a question regarding AMPCO number 51. Oh, I am sorry, I am looking at my screen on my computer. I am so sorry.

In AMPCO number 51, we asked about the difference between the business case that was filed in November 2013 and then the business case that was filed in 2015, and under bullet number 2 you indicate that the schedule was updated to be consistent with the RQE high-confidence schedule.

So does that mean that the schedule in 2013 was a P50 schedule and now the schedule is P90?

MR. ROSE: Can you repeat that last part of the schedule? In 20...

MS. GRICE: 13, was a P50 schedule or a confidence --

MR. ROSE: The schedule in 2013 wasn't a P anything. It was -- you know, we carried 36 months for what we thought the duration might be and didn't lock in on a probability of that schedule until we completed RQE. I mean, that was one of our, you know, our repeated messages through the definition phase, is that we did not want to lock down on our schedule or cost estimate until we had done sufficient planning to be able to be confident that we could lock down on their schedule and cost estimate, so I can't assign a probability to the 36 months that was in the 2013 evidence.

MS. GRICE: Okay. So then in the evidence we have got the critical-path schedule, and then we have got a schedule that adds -- let me stop there.

The critical-path schedule is 107 months total?

MR. ROSE: So let's -- can we talk about -- do you want to talk about unit 2? The unit 2 critical-path schedule is 35 months. The P90 is 40 months.

MS. GRICE: So I guess that's what I am looking for, is we -- in evidence we have got a contingency at P50 which is 1.4 billion, compared to a P90 contingency at 1.7. We have got a schedule for P90. I would like to see what the corresponding schedule is for P50. Is that in evidence anywhere? And I am looking at each individual unit and then all units as a total.

MR. ROSE: I think in the business case we have provided the P50 durations. The difference between P90 and -- so when you think about the critical path from the start

of unit 2 through unit 1 -- sorry, start of unit 2 through unit 3 and then through unit 4, because unit 1 floats underneath those other units -- at P50, subject to check -- and maybe I should take an undertaking before I get myself down a swirl here, but it's probably about five months shorter than the P90 in total.

I would -- we probably should take an undertaking, and I can confirm that P50 total duration.

MR. KEIZER: Maybe you could -- could you ask -- can you just phrase the undertaking again just so we are clear, since...

MS. GRICE: Sure, I am looking for the refurbishment schedule for a confidence level of P50.

MR. ROSE: Just one minute. We are going to pull it up for you.

MS. GRICE: Overall and by unit, or...

MR. KEIZER: Probably give it overall. I am not sure we are going to give it by unit.

MS. GRICE: Okay, overall, please.

MR. KEIZER: So I understand it's CCC 22, attachment 1. But it may be just as easy to take the undertaking at this stage, just to make sure that everybody is looking at the right number and right thing.

MR. REINER: If you turn to CCC 22, attachment 1, page 6 of 13, there is a table at the bottom that speaks to median confidence, which is P50. I believe that was issue 4.5, CCC 22, attachment 1, page 6 and page 7, there is a table 3 that shows you the median confidence or P50

schedule durations, and the high confidence or P90 schedule durations.

MS. GRICE: So I just want to confirm. So this says 109 months and at a P90, it's 112 months. So it's a three-month difference; is that correct?

MR. ROSE: On the four units, yes, that is correct.

MS. GRICE: Okay, thank you. And I just have a question -- now this is regarding Staff 73, attachment 8, page 19.

MR. REINER: I believe we have it here in front of us.

MS. GRICE: Okay, I just wanted to understand. So in terms of the contingency, you have got 0.8 billion in project contingency and 0.9 billion in program contingency.

And then at the bottom of page 19, it just shows that some of the risks from P 70 to P90 could have been allocated to management reserves.

Is that something that OPG could have done in this estimate? Could you have broken out?

MR. ROSE: So that is not the way we have done it here. The management reserve is above and beyond the current business case that we have provided. The P90 is the contingency for the risks that are associated with the work that we are performing.

MS. GRICE: Okay, thank you. I just have a question on AMPCO 86, please. This talks about the $50 million contingency, and it's the contingency for resource management bridging between units, and 12.5 million has been allocated to each unit.

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.

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY

6. QUALITATIVE FACTORS OR FACTORS NOT FULLY QUANTIFIED

- **Decommissioning Fund Impacts**: The decision to refurbish Darlington resulted in a decrease in the present value of the liability related to decommissioning. As of September 2015, the decommissioning fund was fully funded, partly as a result of the reduction in the present value of the liability caused by the assumption of Darlington refurbishment.

- **CO2 Reduction**: Darlington refurbishment contributes to Provincial and Federal goals of reducing CO2 emissions from electricity generation. Assuming efficient gas-fired plants would replace Darlington if it were not refurbished, the refurbishment of Darlington would avoid approximately 330 million tonnes of CO2 emissions over the post-refurbishment life of the station.

- **Employment Impacts**: OPG is the largest employer in the Municipality of Clarington employing 2300 employees at the Darlington site, and 500 at the Darlington Energy Complex working on the DRP. Approximately 60% of Darlington's employees live in Durham Region. As of September 2015, over 800 employees are working at the Darlington site on Refurbishment preparations and 2,000 additional workers are expected at peak construction. Indirect and induced employment in Durham Region is expected to be 5,700 jobs.

- **Municipal and Property Taxes**: OPG pays approximately $4M per year in taxes to the Municipality of Clarington, shared with Durham Region and the school boards. OPG also pays an equivalent amount to the Provincial government for Darlington in the form of a "proxy tax".

- **Citizenship and Community Involvement**: OPG provides leadership to community organizations across Durham Region. In partnership with local communities and non-profit organizations, OPG delivers valuable programs for Durham families. OPG has contributed over $23M in community investment support in Durham Region between 1999 and 2011. In addition, OPG employees raise approximately $1M annually in Durham Region through the OPG Charity Campaign.

7. RISKS

A detailed risk register and a Risk Management Plan has been developed and issued for the DRP. Risks at both the project and program level are identified and mitigating actions are prepared to ensure that each risk is appropriately managed.

Key Risks covering both the DRP and the post-refurbishment operations period are summarized below:

- **DRP Costs and Schedule:** There is a risk that, even with the contingency, there could be cost and schedule overruns. Given OPG's investment of $2.2B in Definition Phase and the level of contingency included in the RQE, Management believes that these risks are manageable within the current cost and schedule estimate. Insurance premiums of $116M are included in the estimate to purchase coverage to mitigate some of the financial risks; these cover Course of Construction-Property, Wrap-Up Liability, Marine Cargo and Advance Loss of Profit, Nuclear Energy Physical Damage-Property, and Delayed Start-Up.

- **Post-Refurbishment Station Performance:** An average station performance of 88% capability factor is assumed over the post-refurbishment life which is considered to be medium to high confidence as it is below the station's demonstrated performance over the past 10 years of 89.4%. Sustained past performance provides confidence that the post-refurbishment performance will be the same or better than the business case assumptions; however, execution of appropriate maintenance and life-cycle management programs during the life of the station to maintain the reliability, will be essential. The post-refurbishment costs include $4.4B ($2015) of ongoing sustaining investments to maintain the condition of the plant.