UNDERTAKING JT1.14

Undertaking

TO ADVISE THE NUMBER OF HOURS SPENT ON THE REACTOR FACE

Response

The context for this undertaking is shown in the Technical Conference transcript of November 14, 2016, p.68, line 16 through to p. 70, line 16 and with reference to OPG's responses to Ex. L-04.3-2 AMPCO-084, part d) with respect to an estimate of the number of hours a typical reactor crew would spend at the reactor face during a shift.

The Technical Conference transcript indicates that crews work 12 hour shifts, however, the majority of crews will work 10 hours shifts. Based on the shift crew schedule, crews working on reactor face work will normally be on the reactor face for 6 hours out of their 10 hour work shift. There are another 2 hours during that shift when the crews will be involved in non-reactor face work. The remainder of the 10 hour shift will be spent in pre-job briefings, getting into and out of personal protective equipment and on mandated breaks. In order to cover the job 24 hours a day, the Re-tube and Feeder Replacement vendor will deploy 4 crews in a staggered manner during the 24 hour period, with each crew being on the reactor face for a total of 6 hours during each 10 hour shift.

The schematic below shows how one shift will be deployed on the reactor face. There is no time during which no crew is at the reactor face.

25 min	3 hours	25 min	120 min	35 min	3 hours	35 min
Pre-job brief/ Getting ready to go to Reactor Vault	Work on the reactor face	Getting out of Reactor Vault /protective equipment (e.g. plasticsuits)	Non vault work	Getting ready to go back to Vault	Work on the reactor face	Getting out of Reactor Vault /protective equipment (e.g. plastic suits) /end of shift

UNDERTAKING JT1.15

Undertaking

TO PROVIDE OPG'S RESPONSES TO THE RCRB RECOMMENDATIONS

Response

As noted in Ex. L-4.3-15 SEC-037, the Refurbishment Construction Review Board (RCRB) has performed two assessments of the Darlington Refurbishment Program as of November 15, 2016. Attachment 1 provides the actions and status of the RCRB recommendations.

ID	Title	Owner Organization	Meeting Source	Action Owner	Action Delegate	Description	Date Identified	Due Date	Date Complete	Status	Status Notes Comments
7708	RCRB - MtPI - Identify top 10 metrics to manage to ("Scorecard").	Planning and Control	External Oversight RCRB	Gary Rose	Lindsay Greenland	1. Identify top 10 metrics to manage to ("Scorecard").	29-Apr-16	31-May-16	31-May-16	Closed	02June2016 - Action complete. "All Hands" metrics presented to NPET and accepted. The top metrics have been established, and implementation plan, including communication strategy is under development. LGREENLAND.
7716	RCRB - VSF - Implement the Use of Vendor Quality Assurance Program	Managed Systems Oversight	External Oversight RCRB	Dave Stiers	Frank Dias	1. Implement the Use of Vendor Quality Assurance Program (CAP)	29-Apr-16	31-May-16	03-Jun-16	Closed	Vendors have implemented their QA Program. Part of that QA program is the CAP program, which are being implemented and gaining traction within the vendors workforces. Oversight of their CAP will be done to ensure that it is reaching the right balance between Vendor and SCR programs.
7684	Quick Win - RCRB - Communication strategy improvement a)	Refurbishment Execution	External Oversight RCRB	Sean Toohey		a. Re-focus the Weekly Message – focus on mindset/execution.	29-Apr-16	07-Jun-16	24-May-16	Closed	This was done starting on 24 May, the "Message of the Week" focus was changed.
7686	Quick Win - RCRB - Communication strategy improvement c)	Refurbishment Execution	External Oversight RCRB	Sean Toohey		c. Conduct an Offsite Alignment Session (NPET and Band Fs) – focus on shift to execution	29-Apr-16	09-Jun-16	08-Jun-16	Closed	This offsite will be combined with the offsite for NSC being led by Bill Owens., and will accomplish this same objective. The Offsite is scheduled for June 8 and includes Vendor Leadership. Due date changed to reflect scheduled date. Session was held, feedback was collected from representatives of P&M, MSO/Contract Mgmt; Vendor Partners, Fleet OPS and Mtce, Station Mtce, Stn WM, Refurb Execution, P&C, People and Culture, Engineering and Construction. Path forward is to use further focus session with wider participation to continue to build the consensus as well as direct communications, Cornerstone Meetings, all hands sessions and 'roll outs' to continue the "Shift to Execution and ONE TEAM" philosophy.
7689	Quick Win - RCRB - Implement 'Tidy Friday'	Refurbishment Construction	External Oversight RCRB	Ken Hobbs	Grant Howard	8. Implement the Friday afternoon worksite clean-up (Tidy Friday) and Housekeeping Standards/Clean As You Go focus	29-Apr-16	10-Jun-16	07-Jun-16	Closed	Due date changed to Align to Top 10 TCD of June 10, 2016. Tidy Friday plan has been initialized. This was communicated in Refurb PCC and daily package as well as in the Station POND package. Expectations are staff will clean as you go and major clean up on the last hour of every Friday. Work group managers are held accountable to inspect job sites and their staff office areas. This will be monitored by Construction Execution oversight and Prods and Mods as well as station Operators.
7685	Quick Win - RCRB - Communication strategy improvement b)	Public Affairs	External Oversight RCRB	Scott Berry		b. Implement 9:45am All Hands Weekly Standups (was Huddles) – RPO and DEC	29-Apr-16	15-Jun-16	22-Jun-16	Closed	On-track: plan complete and approved. First Standup to be launched June7. Vendor plan in progress as well. Email Berry to Meteer, 2016 05 24, GBM Extended at DR meeting - new TCD 15 June 2016. GBM First 'stand-up' held on June 22nd. GBM 20160704
7713	RCRB - MtPI - Complete org chart reviews and transition to project org	Planning and Control	External Oversight RCRB	Ian Sansom	Ryan Smith	6. Complete org chart reviews and transition to project org	29-Apr-16	15-Jun-16	14-Jul-16	Closed	Gary to close week of June 6th, new TCD 20160615. GBM 20160613. 2016July08 - Meeting - Changes to Owner, Rose to Sansom, and delegate added as Smith,Ryan, TCD revised to 15 Jul. Ryan to provide status and close. GBM 2016July13 - SMITHRY - This has been completed. The new project organization, and the interface with the NR and P&M project offices, has been completed and will be reflected in the NR U2 execution estimate.
7714	RCRB - MtPI - Review Change Control Process and add coding to segregate those initiated by a Contractor or OPG	Planning and Control	External Oversight RCRB	Gary Rose	Tracy Leung	7. Review Change Control Process and add coding to segregate those initiated by a Contractor or OPG. Also, add code list re: 'Types' of changes to cover off Recommendation 15.	29-Apr-16	15-Jun-16	31-May-16	Closed	Change Management Process N-MAN-00120-10001 PC12 Section 6.1 states a list of "Change Classification Codes". Each code is designated with the prefix "-OPG" or "-vendor" to denote whether the change was caused by the vendor or caused by OPG. The change classification is also a field in the change header in Ecosys.
7722	RCRB - Other - Project commercial risk management	Planning and Control	External Oversight RCRB	Gary Rose	Ryan Smith	2. High consequence/low probability and FIAK/FIAW risks are being fully assessed currently. Risk Management to review Steam Generator risk and discuss with project team and assess value in third party review (18) Project Risks: Several commercial risks should be carefully managed:• Vendor material cost increases (prices not fixed in contracts). • Schedule Change Impacts (schedule is still live and a potential gap is being created between the current schedule and the contractual schedules). The fact that schedules are not yet resource loaded may also imply changes and bring cost impacts due to changes in resource quantities and cash flow curves.• Change Orders have the potential to increase the Target Cost. Scenario analysis should be done to understand potential pessimistic outcomes and have mitigation plans in place.• OPG removed risk / contingency from the JV price prior to contract signing on the assumption that "OPG is the best party to manage such risks". Contingency was then allocated. An independent verification of the risk dollars removed versus the contingency added should be performed to ensure consistency in this approach.• Cost of closing documents and final "sign-off" of systems is not included in the schedule. This is real work. Updates to the schedules should reflect this reality, and cost impacts should be allocated to the appropriate budget line items in the cost forecast.	29-Apr-16	15-Jun-16	15-Jun-16	Closed	15JUN2016 SMITHRY: Exact duplicate of 7723. Closed to 7723.
7691	Quick Win - RCRB - Communicate the following regarding islanding	Operations and Maintenance	External Oversight RCRB	Boris Vulanovic		11. Communicate the following regarding islanding:• the physical islanding strategy for the refurbishment unit including system islanding strategies and use of Protected Equipment Zones (PEZ) within the island.• defined boundary points with the operating station which will define the division between controlling authorities. • Strategy for defined terminal points where vendor applied lock-out-tag-out will be utilized.• training plan for station integration and unit islanding including the comprehensive training needs analysis.	29-Apr-16	24-Jun-16	23-Jun-16	Closed	Due date extended to June 24th. Steve Gregoris removed as delegate. Action is in Progress. · Initial communication of Islanding strategy and documentation has been provided to the PMO group in preparation for the upcoming RCRB – this is leaded onto a dedicated sharepoint folder. A detailed powerpoint presentation will be ready for review July 13 for presentation to the RCRB team on their upcoming visit.

7674	Quick Win - RCRB - PMs to create top 10 list by bundle.	Refurbishment Execution	External Oversight RCRB	Bill Owens		1. PMs to create top 10 list by bundle. SVP Execution to create roll-up top 10 list. Lists to contain the # days the issue/risk could add to the schedule and a due date of when the issue/risk must be resolved by (or it will go into the schedule). Post Top 10 list in the workplace. Review status at cornerstone and other meeting forums.	29-Apr-16	30-Jun-16	24-Jun-16	Closed	Top 10 list has been generated, and senior team has met to review. Lock down of resolution dates to be finalized. D. Baird for B. Owens, 19MAY16. Update 27MAY16: Dates have been confirmed and finalized. List reviewed and status updates provided at various meetings. Next review scheduled May 31 at Execution DR meeting, and follow-up meetings to continue. Next RMO update end of June. D. Baird for B. Owens. June 24: The Top 10 list has been generated, posters mounted and updated continuously at the DEC and RPO, and as actions are completed, new actions are added to the listing. This will be an fluid action list with continuous actions added and subsequently tracked to completion. Action complete. D. Baird for B. Owens.
7712	RCRB - MtPI - Conduct Benchmarking on metrics	Planning and Control	External Oversight RCRB	Gary Rose	Lindsay Greenland	5. Conduct Benchmarking on metrics (consult with Mike Rencheck). Consider CII top metrics for large projects.	29-Apr-16	30-Jun-16	24-Jun-16	Closed	24June2016 - Benchmarking is complete. Project reporting has been reviewed from the following sources. - Bruce Power project Controls, CII top Construction Metrics, Watts Bar, Pickering RTS, Lower Mattagami River Project, Peter Sutherland Sr GS Project, Pt Lepreau. Tennessee Valley Authority, A comprehensive list of KPIs have been developed, and the top KPIs have been identified. The takeaways from the sources benchmarked are being reviewed for inclusion in Refurb project and program reporting. 03June2016 - Benchmarking in progress. The following groups/sources have been reviewed. Bruce Project Controls, CII top construction metrics, Pt Lepreau.
7699	RCRB - Implement and optimize the Nuclear Resourcing Program	Human Resources	External Oversight RCRB	Nicole Lichowit	Kris Oomen	13. Implement and optimize the Nuclear Resourcing Program per established plan inclusive of increasing recruitment resources , implementation of process and policy changes and reporting of metrics through the dashboard. Finalize RFP for preferred vendors. Establish pro-active partnerships with vendors, unions and the business.	29-Apr-16	15-Jul-16	11-Jul-16	Closed	Program changes communicated at NPET. Implementation schedule in progress. RFP in negotiation phase with selected vendors.
7721	RCRB - Other - Risk Management	Planning and Control	External Oversight RCRB	Gary Rose	Ryan Smith	a. The schedule does not include resource loading and the identification of handoff points. The RCRB believes these present one of the greater risks to the refurbishment schedule, but are not among the most important risk items. b. Another potential risk is the new inspection ports to be installed on the Steam Generators. The RCRB recommends that an independent group review the process and the risk associated with installing Steam Generator lancing ports. (Information is being collected to provide to the RCRB). Other high consequence items should be identified and reviewed.	29-Apr-16	15-Jul-16	14-Jul-16	Closed	SMITHRY 24JUN2016: Recommendation 13a) Currently in process and resources are being loaded by the Schedule team. The Rev C schedule to 62% complete (including resource loading), as committed as part of the recovery milestone was achieved on June 17. The finalization of the resource loading and issuance of the Rev 0 schedule will happen August 25. A series of offsite vertical and horizontal slice reviews are in process at the time of this update, which will flush out the remaining integration and interface issues and risks. The RM department has mapped all existing risks in RMO to execution windows and is participating directly in this offsite exercise to extract any additional risks that need to be considered. In addition, the OP2210 Milestone "Risk Mitigation Plans Complete" milestone is well progressed with all bundles and Operations and Maintainence undergoing challenge meetings for top risks, integration risks, and human performance risks under the scrutiny of the NR SVP, the Unit Director and the Risk Manager. This was completed on schedule for Jun 21 with part B of the milestone due August 12th to finalize the items that require built in contingency activities for items with residual risks deemed too high by score (15 and over) or UD judgment. 13b) Refer to Attachments. A detailed FOAK/FIAW challenge meeting was held specifically dedicated to the installation of the access ports on April 12. Refer to risk 11278 in RMO for actions. 2016July08 - Meeting - Ryan to update status and close. GBM 2016July13. SMITHRY 14JUL2016 - This action is closed. Vertical and horizaontal slice review are ongoing and a fully resource loaded schedule is on track for August 25th.The project team for SGs was consulted in detail and it has been confirmed that via previous similar work, OPEX reviews, work planning, etc. that the access port installation to the SGs could not result in a write off of those assets. Of major concern however is the FME considerations upon unit startup, which could have such an impact. This technical risk has been escalated to the senior levels of the organization, the enterprise risk management organization, and is being considered and built in the development of the schedule, including HTS flush considerations, crud burst considerations, and hot conditioning considerations to mitigating the impact of leftovers from the work being undertaken during the outage.
7696	RCRB - Implement a paper closure program/program lead	Quality Management	External Oversight RCRB	Imtiaz Malek		7. Implement a paper closure program/program lead (configuration management, CAP, Management Actions, RFIs, Design Paperwork, SAFs, etc)	29-Apr-16	15-Aug-16	05-Aug-16	Closed	July 19, 2016: In independent industry expert has been brought in to review processes in place to ensure paper closure. This includes a review to confirm if processes are in place to ensure documentation is prepared in a timely fashion, resources needs, issue areas. Review will identify bottle necks/issue areas, confirm if size of refurb organization to ensure paper closure is adequate and metrics are in place to monitor overall status. Aug 9, 2016 Update: Marci Cooper (US Consultant) as recommended by RCRB has completed a review of our Paper Closure process. She spent over two weeks to talk to key stakeholders and has presented her findings to Mike and his DRs. Marci will be coming back as an expert lead for the documentation closure process starting September 2016, pending paperwork completion. As per her recommendation a team will be formed to review all the packages prior to AFS.
7718	RCRB - VSF - Develop, document and implement the CWP tear out program	Refurbishment Construction	External Oversight RCRB	Ken Hobbs	Peter Robson	3. Develop, document and communicate the "typical" CWP tear out – update the CWP guide to reflect "typical" Vendor CWP tear outs.	29-Apr-16	31-Aug-16	30-Aug-16	Closed	Initial meeting is planned for week of July 12. The meeting will include reps from JV, ES Fox and B&M. Larry Mann is the lead for the initiative. (Complete) 1: Key Vendors discussed and agreed to the reduction in documentation initiative. Agreement with the language revisions by senior level (OPG/Vendors) was achieved. (Complete) JV-Todd Hamilton, Fred Milko ES Fox-John Puopolo B&M- Jim Whyte Prods/Mods-Pat Kennelly, Grant Howard Quality Management- George Tsakiris 2: Guide updated and sent for issuance. Communication to key Vendors and OPG Orgs involved to start driving behaviors supporting "less is better". TCD Aug 25 2016 (Complete) 3: Guide revision sent for issued in Asset Suite. Aug 31 2016. (Complete) 4: Perform a snapshot assessment with Vendor participation. TCD Jan 29, 2017. (RF16-001955-SA input into SA database)
7720	RCRB - VSF - Revisit Vendor efficiencies inside the island (SATM, LOTO, seismic scaffold,	Refurbishment Execution	External Oversight RCRB	Ken Hobbs	Grant Howard	6. Revisit Vendor efficiencies inside the island (SATM, LOTO, seismic scaffold, steam doors, etc)	29-Apr-16	31-Aug-16	07-Jul-16	Closed	A review has been conducted with the key vendors to reconfirm which OPG processes will be used. A path forward on common use procedures has been agreed upon. All Unions have accepted that their workers will receive a standardized training package/NQW (Nuclear Qualified Worker) which includes some of the common use procedures, and that training will be done through the Union Halls which will permit them to utilise for work at both OPG & Bruce Nuclear.

	steam doors, etc)										Vendors will gain efficiencies by using non-OPG procedures where appropriate. Lock Out Tag Out (LOTO) has been address with the JV and is in progress with ES Fox, Black & MacDonald and BWXT. A separate RMO Action 8281 has been initiated to track this to completion. Issues related to the SATM program have been identified and will be address via the Refurb TOP 10 list.
7719	Quick Win - RCRB - VSF - Conduct time and motion studies to drive productivity	Refurbishment Execution	External Oversight RCRB	Gary Rose	Ken Hobbs	5. Conduct time and motion studies to drive productivity (consult with Rencheck). Interim studies being conducted currently by Ken Hobbs	29-Apr-16	07-Sep-16	06-Sep-16	Closed	1. Interim Study Completed by Construction Execution Oversight Personnel documenting start of shift, breaks, lunch, end of shift times. 2. Meeting with external Vendor completed for Tool Time Study, PO paper complete. Study to schedule for Aug 21 to Sept. 02, 2016. TCD had to be revised as F&G did not have security clearance and the Site Evacuation Drill on Aug. 31. F&G will have to be sponsored and escorted for duration of study CLOSEOUT NOTES: Time in Motion Study was completed by F&G during the dates of AUG21/16 to SEP02/16. Data will be supplied in a detailed report over next few weeks and presented VIA WEBEX. Action completed and report will be entered as Self Assessment when data supplied. REF- SA RF16-001965-SA .
8281	RCRB - Confirm acceptance of Lock Out Tag Out (LOTO) process	Refurbishment Execution	External Oversight RCRB	Boris Vulanovic	Dan Cowley	Confirm acceptance of Lock Out Tag Out (LOTO) process from ES Fox and BWXT	07-Jul-16	30-Sep-16	17-Oct-16	Closed	Both ESFOX and AECON LOTO have been accepted, action complete October 17, 2016 L.Laking for B.Vulanovic. Refer to action item 7720 for relations to this action. 12 July2016: Owner changed from Ken Hobbs to Boris Vulanovic at SVP Execution DR meeting. F. Dias. 13JULY2016 Delegated updated to align with Boris Vulanovic ownership as per Ken Hobbs Equivalency evaluations of ES Fox and AECON / JV Lock Out Tag Out process has been completed and equivalency approved by Boris Vulanovic. NK38-CORR-09701-0615241 is in the signature process and will be uploaded by Tuesday October 11th.
7705	RCRB - SRL - Disposition the 40 Open Items	Work Management	External Oversight RCRB	Karen Fritz		4. Disposition the 40 Open Items	29-Apr-16	15-Oct-16	25-Jul-16	Closed	At time of RMO input, there were 40 schedule issues that were affecting the quality of the Rev C schedule. This 'issues' list is a live database which sees issues resolved and new issues identified as detailed planning takes place toward a Rev 0 schedule. Currently Mike Allen holds an 'Issues' meeting every Friday morning to deal with any issue that is not being specifically dealt with at some other forum. As issues are discovered they are added to the RMO tool and as they are resolved they are dispositioned. The due date for dispositioning all open items is Revision 0 schedule.
8997	RCRB Visit #2 - i) Completion of Work as Scheduled	Refurbishment Execution	External Oversight RCRB	Bill Owens		ISSUE #1: Currently, the execution of the pre-requisite refurbishment work is behind schedule and a "bow wave" of activities is starting to occur. Only 21 of 67 prerequisite work windows are complete or on schedule, the remainder are delayed. A work completion rate of approximately 150 tasks per week is currently being completed. A rate of 2 to 3 times that will be needed to complete the prerequisite work prior to the shutdown of the unit. In addition, execution of some of the planned work is progressing more slowly than expected due to the complexity of the work, late discovery, or late identification of issues (e.g. Shutdown Cooling HX replacements). Portions of this work is key to the start of the project and has completion dates that are 'just in time' for their use. The current schedule for a number of the prerequisite activities have little float. For example: · The construction of the waste processing building, which is required to receive re-tube waste has little float. · The sequence of Shutdown Cooling HX replacement, Primary Heat Transport System heavy water transfer header maintenance, and the unbudgeted outage to address the STOP modification short-falls will require good co-ordination and has little schedule float. RECCOMMENDATION #1 The RCRB recommends that action is taken to both understand why the desired task/work off rate is not being achieved and take the required actions to ensure this work is completed as scheduled. It was noted during the review week that no routine "T+1" type meeting is held to both identify and rectify schedule challenges and hold staff accountable for achieving the schedule. Carrying out schedule reviews may partially rectify this issue.	06-Sep-16	30-Oct-16	13-Oct-16	Closed	Completion Notes: See attachment RRSA Recommendations for program initiatives related to meeting pre-req completions. In addition, the following initiatives are underway as of Sept. 6, 2016. 6 Sep 2016 Update Several initiatives are underway in support of increasing the completion of work as scheduled: 1. A T+1 meeting is held each week to review performance during the T-0 week and make improvements 2. A Baseline Schedule meeting is held each week with Project Managers present to determine – what work did not get done and why work was not completed as planned, and to take action to increase completion rates in future weeks. Mtg chaired by K. Fritz. 3. A T-4 meeting is in place to look ahead and address any barriers to completion of work during the T-0 week. The CWP tracking meeting has been consolidated with this meeting. 4. Vendors are now applying HOLDs to scheduled work when required for materials, work plans, CWPs etc. which will provide clarity on work readiness 5. A station interface conference call is held daily to address integration issues through the PCC. 6. The first 15 minutes of the daily SMSB includes a review of the Top 3 Station and Top 3 Refurb Interface issues 7. A dashboard is provided at the PCC that shows Task Rate, T-2 survival and Pre-requisite progress by bundle and by Vendor 8. Vendors have committed to meet work rate completion milestones by Oct 4. 9. Time and motion study in progress (to identify productivity issues).Action complete, Deb Baird for Bill Owens, Refurb Execution, 13OCT16.
8999	RCRB Visit #2 - ii) Closeout of Construction Work & Return to Service planning	Refurbishment Execution	External Oversight RCRB	Boris Vulanovic		ISSUE 2. The level of readiness to execute the project is most advanced in the 'lead-in segment' (but decreases with subsequent segments), for example; · The level of preparation, teamwork, and ownership for the reactor defueling appears to be good. · The level of preparation for the installation of the 'bulkhead' appears adequate. · The RFR component of the 'removal segment' (removal of reactor components such as pressure tubes etc) appears to be well planned. The use of the mock-up is a valuable tool, and is being used to practice and to perform tool testing. Work activities such as the Heat Transport Pump motor movement (currently a requirement exists to stop work in the reactor vault while hoisting motors) and the currently planned radiography in the reactor vault could still impact the critical path schedule, and have not been resolved. (Note, this is not an all inclusive list). ISSUE 3. Project preparation, planning, and scheduling is incomplete in part due to the processes and infrastructure to close-out the construction work, complete the necessary documentation reviews, and then plan and execute the commissioning and "return to service" activities are not well advanced. Scheduling the return of plant systems should govern how the construction work is sequenced. Failure to follow this pattern will result in having to revise the schedule and add to the required resources to complete the schedule. The RCRB considers this crucial to the success of the project. Once the unit is shut down and defueling is commenced, the RCRB is concerned about the organization's ability to manage the challenges of execution while completing return to service planning. Key resources such as availability of certified staff	06-Sep-16	30-Oct-16	28-Oct-16	Closed	Update October 28, 2016 on behalf of M. Stewart This action is complete. Update 7 Oct 2016 by M. Stewart: RTS is mobilizing the Completion Assurance Group to support document closure for RTS activities (CCD, MAFS, SAFS and RCHP's). A new Documentation Closure group with the responsibility to interface with the projects, OPG stakeholders and RTS has been formed. Terms of Reference Documentation Group for Darlington Nuclear Refurbishment (DNR) Background There is a concern that all required documents may not be available prior to critical milestones {i.e.: Construction Completion Declaration (CCD), Available for Service (AFS), Systems Available for Service (SAFS), Restart Control Hold Points (RCHP), Return to Service (RTS) and Closeout} for the DNR project. Objective Configuration management and records retrievability must be maintained to support critical milestones leading to RTS and to support configuration control post refurbishment Scope The scope of work includes managing documentation flow from start to completion of work and RTS of the Units. The function of the co-ordination group will include: 1. Co-ordinating and securing resources to manage documentation flow of records in a timely manner for, Technical Reviews, CCD, AFS, SAFS, RCHP, RTS, and Closeout in VenDM and AS7, as required; 2. Engaging with key stakeholders both within Vendors and OPG to ensure adequate resources are secured for the review of documentation based on planned look ahead; 3. Supporting RTS group to ensure documentation co-ordination allows for timely close out of RTS documentation and to support clearing regulatory hold points; 4. All documentation associated with DNR scope executed by the Projects & Modifications group Items not to be included as part of the Documentation Coordination Group · Conducting technical review/approval of controlled documents Activities · A centralized Documentation Coordination Group shall be established to optimize, co-ordinate the stakeholder engagement to apply resources for documentation reviews and monitor the process for maintaining configuration control (i.e., paper and plant) for the DNR

						with project experience will be at a premium. In addition, with all the issues that the management team currently has to manage (for example the need to develop mitigation plans for potentially late campus plan projects), then add the inevitable discovery issues with a shutdown unit in the execution phase. It is critical for the success of the project that these issues are resolved in a timely manner. RECOMENDATION #2 a) It is the RCRB experience that some form of "close out group" needs to be created to ensure that the close out of construction work is done correctly and timely (with quality and ensuring that gaps do not exist which demonstrate the work was completed as specified). There is considerable project related OPEX to support the formation of this group or function. Currently within the "Projects and Modifications" group, elements of this function currently exist and could be modelled. b) As discussed above, a return to service group needs to expeditiously complete both the conceptual and detailed planning associated with returning of layed up / operating and modification systems and components to service. This activity needs to be monitored and tracked by the Refurbishment management team.					project. · Develop and document process for optimizing the deliverables required to ensure that documentation peaks are properly managed. This should include, as a minimum: o Engagement of key Stakeholders (Vendors and OPG) to establish what actions will be implemented by whom including resources {Engineering, Modification Team Leader (MTLs), Project Mangers (PMs) for Vendor & OPG, Operations (OPs), Licensing and CIO} o Coordination & planning (receiver & reviewer) - Plan & coordinate documents production, tracking, quality for review and submission to CIO in AS7 ahead of CCD, AFS, SAFS, RCHP, RTS and Closeout) o Enable timely periodic Technical Reviews (e.g.: at ~25%/50%/75%) · Roll out expectations to vendors and OPG stakeholders · Implement processes · Establish metrics and reporting to ensure its effectiveness Oversee use of VenDM per COIR
9001	RCRB Visit #2 - iv) Operational model	Refurbishment Execution	External Oversight RCRB	Ken Gilbert		ISSUE 5: Currently, the project is being managed from the 'online' operational perspective. It is being viewed as a 'very large planned outage' using traditional outage processes. From experience on past refurbishment projects, the RCRB views this as a significant challenge to efficiently use those processes to manage the project, given the scale of work being planned and executed. The "operational model" for this project needs to change, and be based on: eliminating unnecessary reviews and approvals, streamlining of processes to support work execution, and only requiring operational involvement where value is added. In addition, except for OP&P revisions, there have been few requests for relief on reactor safety constraints (e.g. SLOD, Single Line of Defence) from Refurbishment staff. There are a number of interface issues between the site and the project that needs to be resolved, and are well behind when they should have been decided. These are adversely affecting the organization's ability to obtain clarity on standards and expectations associated with execution of the project. RECOMMENDATION #4 One of the fundamental premises of a strong culture is to ensure that written expectations exist; staff need to understand the expectations and then follow them. In addition, with the reactor defueled and the unit separated from containment there exists a once in the life of the operating unit an opportunity to streamline the work processes so only those that truly add value (be it from a safety / quality / schedule or cost perspective) are in effect. In order to achieve these two basic principles a team needs to be struck utilizing personnel with external project experience to do the following: · Review the expectations associated with the execution of work (be it approvals to go to work / approvals to modify work instructions / modify designs packages / expectations for how work is carried out etc) · Identify the value added components (and eliminate the non value added components) · Look to minimize the operational constraints and constraints posed by operations personnel · Obtain craft and vender input as to what constraints appear not to be adding value · Ensure that constraints that may be relaxed are taken into account in the return to service process · Produce a refurbishment document set for staff to follow defining the expectations for doing work and when they apply (which phase or segment in the project they apply). In addition transition plans need to be in place to move between project work segments (as referenced in the level 1 project plan) or between states as referenced in the Operating policies and principles.	06-Sep-16	15-Mar-17		In Progress	Identify high impact opportunity in the current work execution process for potential streamlining and develop and document alternate processes **Status** Construction Switch represents the concept that many of the operational constraints and restrictions associated with a nuclear generating unit may be changed when the irradiated fuel has been removed from the reactor and the unit has been separated from Containment. Those practices, while effective in protecting the public and the fuel often require techniques or compensatory measures that prevent the work from being performed as efficiently as it could have been and therefore expensive. Initial approach is address inefficiencies in work execution in four areas: **Work Approval Delay** Address inefficiencies in several areas related to obtaining work approval. This includes: - Stakeholder Input into CWP: Perform stakeholder reviews of vendor generated work execution documents by station staff to identify and correct potential worksite issues not recognized by the document author - Update governance to remove inefficiencies and eliminate duplication in the review of work execution documents (ITPs and work instruction) - Establish a dedicated work control facility to minimize distraction of the shift crew and to eliminate delays associated with interacting with the operating crews (who may be focused on operational priorities) - Align governance to allow pre-authorization of work - Align governance to allow pre-coding of work to eliminate unnecessary interaction of construction staff with OPG issuing authorities - Implement a nuclear refurbishment Work Protection Code to reduce delays in obtaining working rights and improve efficiencies through coordinated testing - Revised licensing documents (OPP) to ensure approval level is aligned with plant risk as the unit enters each refurbishment segment (thereby eliminating unnecessary levels of approval) **Operating Unit Impact or Distraction** Eliminating inefficiencies associated with using the station operating crew to coordinate or execute refurbishment work. Actions to date include: - Turnover of the Refurbishment unit to a dedicated refurbishment organization - As above, establishing and staffing a dedicated work control trailer to support refurbishment work execution - Integrating activities with the potential to impact station operation into the station work schedule **Worksite Delay** Reduce inefficiencies associated with work site delays. Actions include - Ensuring availability of RP equipment and RP support staff - Revising governance to ensure procedure changes at the work-face are efficient while ensuring approval levels are aligned with the risk associated with the reactor state **Work Inefficiency** Reduce or eliminate inefficiencies associated with operating and maintenance practices which are not required in the defueled and islanded state. Areas to be addressed include: - Revising OP&P to remove unnecessary constraints and restrictions which do not apply in the defueled/islanded state - Establishing system and process conditions consistent with revised OPP - Opening airlock doors to allow efficient vault access - Relaxing constraints for Refurb unit steam doors to minimize delays in equipment transfer through steam doors - GSS removal to eliminate unnecessary constraints and work restrictions - Eliminate unnecessary constraints and actions normally associated performing heat sink checks and ensuring equipment availability to allow efficient maintenance and refurbishment execution

Planned Action	Owner	TCD
Update governance (CORR and D-FORM-10883) to removing inefficiencies and duplication in the review of work execution documents	Ken Gilbert	Complete Oct 20,2016
Establish a dedicated work control facility to minimize distraction of the shift crew and to eliminate delays associated with interacting with the operating crews	Ross McCord	Complete Nov 1, 2016
Align governance to allow pre-authorization of work	Ken Gilbert	Complete Oct 1, 2016
Align governance to allow pre-coding of work to eliminate unnecessary interaction of construction staff with OPG issuing authorities	Ken Gilbert	Complete Oct 1, 2016
Revise licensing documents (OPP) to ensure approval level is aligned with plant risk as the unit enters each refurbishment segment	Ross McCord	Complete Sept 16, 2016
Implement a nuclear refurbishment Work Protection Code to reduce delays in obtaining working rights and improve efficiencies through coordinated testing	Ross McCord	Dec 30, 2016
Revise operating documents to reflect refurbishment unit OP&P to remove unnecessary constraints and restrictions when in State 3A and 3B	Ken Gilbert	Jan 15, 2017
- GSS: operating procedures to eliminate unnecessary work restrictions in State 3A and 3B	Ken Gilbert	Jan 15, 2017
- Heat sinks: operating procedures to eliminate unnecessary work practices in State 3A and 3B	Ken Gilbert	Mar 1, 2017
- Airlocks: operating procedures to support opening airlock doors to allow efficient vault access		
Revise Nuclear Governance associated with work-site procedure markups to support Vendor procedures	Ken Gilbert	Jan 30, 2017
Relaxing constraints for Refurb unit steam doors	Ken Gilbert	Mar 15, 2017
Finalize work program initiatives and prioritize efficiency improvements for 2017 Q1 and Q2	Ken Gilbert	Jan 30, 2017

7693	RCRB - Get Engineers deployed into the field	Engineering	External Oversight RCRB	Neil A Mitchell	Emily Tarle	5. Get Engineers deployed into the field (Resident Engineers) with the right authority - define how work will flow. 50% already deployed. Additional 50% remaining.	29-Apr-16	30-Nov-16	13-Oct-16	Closed	29JUL2016 - Change Management Plan NK38-REF-01900-0606483 issued July 20. Due date changed to align with final action per CMP. 07JUL2016: ORGANIZATION AND PEOPLE IN PLACE – on target for September 1. · Change Management Plan template has been prepared · Field Services Org structure approved and added to the Refurbishment Engineering organizational chart July 6 · Hiring of 2 candidates in progress (10/20 already in role). · Training needs have been evaluated. · OSS task request prepared for additional start-up support. CONSTRUCTION ORIENTED FIELD CHANGE PROCESS – on target for July 29. · Timely FIC's is now a NR Top 10 action and was presented at Cornerstone July 6. · Field Initiated Change (FIC) Review Board is in its 8th week · Feedback has been received from key vendors on efficiencies for (1) RFI (2) FIC (3) FIC-to-field. · Procedure walk-through completed 2016July08 - Meeting - Above update appended. GBM 2016July13. 2016Oct06 - Update// NR Design Engineering Field Services have a full contingent of 20 staff deployed as planned in support of NR U2 readiness. Hiring of OPG permanent staff continues, with 4 of 9 posted OPG positions filled, 5 positions continued to be filled under a currently posted vacancy. 2016Oct07 - Meeting - To be closed as remaining positions are being recruited, but not required at this immediate time. GBM 2016Oct13
9002	RCRB Visit #2 - v) Accountability / Culture of Tolerance	Refurbishment Execution	External Oversight RCRB	Sean Toohey		ISSUE 6: There is a cultural tolerance for acceptance of work delays. This tolerance for work delays is being enabled by the leadership team. There is a lack of understanding for what it means to be an 'accountable organization.' Example: · Project pre-requisite milestones have moved multiple times · Currently no T+1 nor "schedule adherence" accountability meetings exist RECOMMENDATION # 5 As discussed is this report both in this section and in	06-Sep-16	20-Dec-16		In Progress	This Initiative is documented in SCR # N-2016-25397, from Oct 12 2016. The associated Action requests will provide status going forward. An initiative has been developed to address this shortcoming. Initiative plan, complete with deliverables and dates is attached. Executive Summary follows: Problem Statement RCRB & RRSA observed that there is a lack of understanding for what it means to be an 'accountable organization'. The level of accountability and understanding of what accountability means must be improved on the project. This includes a common

						the observations section, the level of accountability and understanding of what accountability means must be improved on the project. This includes a common understanding by both OPG staff and the contract partners of what it means to be an accountable organization. The RCRB is not suggesting that a management style be implemented that is not consistent with the culture of OPG. OPG does have stated norms and expectations when it comes to accountability and has examples where people and organizations do demonstrate the required behaviors. The leadership team needs to ensure what is expected is clearly understood, then modeled by the leadership team and subsequently re-enforced and coached. For a project with multiple contractors, a number of different types of contacts and a large number of interface points between OPG and its Vendors, it is very important that all people involved are truly ready to execute their work. Failure to have a high level of readiness including having the processes whereby work is executed and closed out, can put the project at risk. It is the view of the RCRB that unless the appropriate amount of progress is made resolving these 5 recommendations, a significant impact to the project schedule and cost will occur.					understanding by both OPG staff and the contract partners of what it means to be an accountable organization. Initiative Description Mike Allen, as an accountable owner, has delegated the execution of this initiative to Sean Toohey. The goal of this initiative is to ensure leaders communicate and reinforce the behaviours that support meeting commitments and a bias for action (Say It, Do It) as one team, in an aligned and focused manner. This includes both the Refurbishment and vendor stakeholders. The initiative builds on work already underway in the areas of setting expectations, communicating an aligned message on supporting Safety, Quality, Schedule and Cost, success measures and reinforcing behaviours. Key stakeholders have been identified that are integral to driving improvement in accountability. These include: 1. The Refurbishment leadership team (including vendor leadership) 2. Personnel executing the work (including vendor personnel)
9000	RCRB Visit #2 - iii) Metrics	Refurbishment Execution	External Oversight RCRB	Gary Rose	Ian Sansom	ISSUE 4: During the RCRB review a number of reports with associated metrics were reviewed. In a number of cases it was difficult to determine how these metrics rolled up to the refurbishment score card. RECOMMENDATION #3 While the project does have a large number of metrics, they do not consistently provide an accurate, integrated picture of project health. The metrics identify individual project performance but do not adequate portray the integrated project execution and status. A "pyramidal system" of metrics and performance indicators is needed to effectively manage a project of this complexity. There are a sufficient number of metrics generated; they need to be strategically applied to allow management to focus on the problem areas. The RCRB recommends on a priority basis, the following changes be made to the existing metric set: · Where qualitative measures of readiness are used, Management needs to ensure a challenge process exists to ensure the rating chosen reflects the true level of readiness. · As was discussed during the on site visit, individual departments need to produce "score cards" supported by metrics which roll up to an "overall refurbishment" score card.	06-Sep-16	31-Dec-16		In Progress	There are a number of actions to this plan. The last action is dated December 31, 2016.

UNDERTAKING JT1.16

Undertaking

TO PROVIDE THE BREAKDOWN BETWEEN CAPITAL AND OM&A AMOUNTS

Response

The following table represents the details that make up the $327 million Capital and $533 million OM&A as per Ex. L-4.3-2 AMPCO-105.

OM&A and Capital Costs Details Underlying AMPCO 105 ($M)	Total
Unit Maintenance / Operations (Online / Outage)	398
Contracted Maintenance Programs (T/G, BOP)	81
Engineering Systems Surveillance Activities	28
Operator Training Program	25
Total OM&A	**533**
Darlington Operations Support Building Refurbishment	63
Darlington Auxiliary Heating System	99
Emergency Service Water Pipe and Component Replacement	7
Primary Heat Transport Pump Motor Replacements & Overhaul	130
Highway 401 & Holt Road Interchange	29
Total Capital	**327**

Note: Numbers may not add due to rounding.

UNDERTAKING JT1.17

Undertaking

TO PROVIDE RESPONSES TO THE ENVIRONMENTAL DEFENCE LETTER FILED NOVEMBER 8, 2016

Response

See attachments A - P.

UNDERTAKING JT1.17
ATTACHMENT A

Undertaking

ED INTERROGATORY #3

The response to this interrogatory indicated that 83% of a 100% cost overrun would be passed on to OPG. If the Darlington cost overrun were to be greater than 100%, will more than 83% of these cost overruns be passed on to OPG? If not, would at least 83% of the cost overruns be passed on to OPG in this scenario? Please use the same assumptions as in the response to ED Interrogatory #3.

Response

Please note that OPG's response to this undertaking should be read in conjunction with the responses to interrogatory L-4.3-7 ED-003 and interrogatory L-4.3-7 ED-004 with particular emphasis on the qualifications OPG has noted in preparing these scenario assessments.

Using the simplified assumptions OPG has made for modeling these scenarios, and subject to the qualifications noted in interrogatory L-04.3-7 ED-004, the answer is yes. In particular, one reason why this percentage will continue to increase is that, as OPG noted in footnote 9 of interrogatory L-4.3-7 ED-004, Attachment 1, for simplicity, for all of the target cost contracts, a 20% cost disincentive was applied above any neutral band specified in the contracts. The actual percentage is calculated using a graded approach where the higher the cost overrun, the higher the disincentive payments from the contractor. However, some of the Darlington Refurbishment Program contracts also include caps on incentives and disincentives. If a disincentive cap is exceeded, OPG will not receive any further disincentive payments in such cost overrun scenarios.

To re-iterate, OPG has provided the calculations in interrogatory L-4.3-7 ED-004 and this qualitative assessment of the proportion of the costs to be borne by OPG in a situation of over 100% cost overrun; however, OPG continues to view these scenario assessments as a purely mathematical exercise, as OPG does not believe that they are representative of how OPG would manage the project and the costs that would accrue in an actual cost overrun situation.

UNDERTAKING JT1.17
ATTACHMENT B

Undertaking

ED INTERROGATORY #5

We asked for Darlington's "annual capacity utilization rates" [i.e., actual output/(3512 MW x 8760 hours/year)], but OPG provided us with the "Unit Capability Factor". Please provide the annual capacity utilization rates.

Response

Please see updated Chart 1 from Ex. L-4.3-7 ED-05.

Chart 1

Year	Installed Capacity MCR Net (MW)	Net Output (TWh)	Annual Capacity Utilization Rate
2005	3512	27.6	89.3
2006	3512	27.0	87.4
2007	3512	27.2	88.3
2008	3512	28.9	93.5
2009	3512	26.0	84.6
2010	3512	26.5	86.3
2011	3512	29.0	94.0
2012	3512	28.3	91.8
2013	3512	25.1	81.5
2014	3512	28.0	91.0
2015	3512	23.3	75.8

UNDERTAKING JT1.17
ATTACHMENT C

Undertaking

ED INTERROGATORY #6

This interrogatory requested the quarterly cumulative capital expenditures for 2017-2020. OPG provided the information for 2017 but not for 2018 to 2020. Please provide a complete response to this interrogatory including the quarterly figures for all years from 2017 to 2020. Please provide this as a revised and updated response so that all the information is clearly laid out in one place.

Response

This Undertaking requests OPG to provide quarterly cost flows for 2018, 2019 and 2020 for the Unit 2 in-service amount of $4.8B. OPG had provided quarterly cost flows for 2017 only and had noted in its response to Ex. L-4.3-7 ED-6 that only annual cost flows were produced at the time of the Release Quality Estimate (RQE) for 2018 onwards. OPG has approximated the quarterly flows for 2018, 2019 and 2020. Please note that these flows will be re-forecast on an ongoing basis as the Unit 2 refurbishment project progresses.

$M	LTD 2016 F/Cast at RQE	2017				2018			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Capital inc. Contingency	2,065	193	188	205	191	205	198	189	189
Interest	215	29	31	34	37	40	43	46	49
Total Capital Cost	2,280	221	220	239	228	245	241	235	238
Cumulative Total Capital Cost	2,280	2,502	2,722	2,961	3,189	3,434	3,675	3,910	4,148

$M		2019				2020
		Q1	Q2	Q3	Q4	Q1
Capital inc. Contingency		94	90	74	70	70
Interest		51	53	54	56	40
Total Capital Cost		145	143	128	126	110
Cumulative Total Capital Cost		4,293	4,436	4,564	4,690	4,800

Notes to the Table:

1. OPG has used the LTD 2016 forecast at RQE to match the RQE flows. The actual expenditures to date in 2016 have been lower compared to the forecast at the time of RQE.

UNDERTAKING JT1.17
ATTACHMENT D

Undertaking

ED INTERROGATORY #7
This interrogatory requested OPG's estimate of the probability that the unit 2 refurbishment will exceed its budget of $4,800.2 M. OPG stated that "OPG does not estimate the probability associated with in-service additions. In-service additions are not analogous to cost estimates." However, OPG indicated in ED interrogatory #1 that the probability of the total refurbishment process exceeding its estimate to be 10%.

OPG has not indicated an impediment to estimating the probability of the unit 2 refurbishment costs exceeding the cost estimate for that unit. Please provide the cost estimate for the unit 2 refurbishment, including interest, escalation, and contingency (if it is different than the in-service addition amount of $4,800.2M). Please provide an estimate of the probability that the actual cost will exceed that estimate.

Response

Please refer to the following Ex. L-4.3-1 Staff-55, Attachment 1, p.13 which shows the Unit 2 refurbishment cost estimate (excluding Definition Phase costs to be placed in-service with Unit 2) of $3.4B, consistent with the Unit 2 Execution Estimate. As the Unit 2 cost estimate is a part of the $12.8B 4-unit estimate and the contingency was calculated on an integrated 4-unit basis, OPG estimates the probability that the actual Unit 2 cost will exceed that estimate to be 10%.

The following chart provides a reconciliation of the Unit 2 refurbishment execution cost estimate with the costs to be placed in-service with Unit 2.

Total I/S Amount	**$4.8 B**
Unit 2 EE Remaining Contingency	$0.7B
Unit 2 EE Costs to completion excluding Contingency	$2.4B
Unit 2 EE Life-to-Date Actual Costs thru June 2016 (Unit 2 Execution Estimate)	$1.7B

UNDERTAKING JT1.17
ATTACHMENT E

Undertaking

ED INTERROGATORY #10 & ED INTERROGATORY #11
According to Page 3 of ED Interrogatory #10, the annual capital cost of the Darlington Re-Build is 3.5 cents per kWh assuming: a) a capital cost of $12.8 billion; b) an average capacity factor of 84.8%; c) a 30 year operating life; and d) a 7% discount rate (see ED Interrogatory #11).

It appears that there may be an error in OPG's number. According to our calculations, amortizing $12.8 billion over 30 years at 7% entails an annual cost of $1,021,900,800. The annual output of Darlington, assuming an 84.8% capacity factor, is 26,088,821.76 MWh [3512 MW x 8760 hours x 0.848]. This yields an annual capital cost of 3.9 cents per kWh. Please confirm whether there is indeed an error. If not, please explain. If there is an error, please recalculate the capital cost per kWh for all the scenarios in ED Interrogatories #10 and 11.

Response

Please refer to the responses to exhibits L-4.3-6 EP-014 and L-4.3-8 GEC-011.

There is no error in OPG's calculation of the 3.5 ¢/kWh LUEC associated with the $12.8B cost of the DRP. Please see Attachment 1 which explains the LUEC methodology.

There are several differences between a LUEC calculation and the simple amortization of the project cost over 30 years provided in the interrogatory. Attachment 2 provides a reconciliation of the LUEC calculation and the simple amortization. The major differences are provided below:

1. A LUEC calculation uses present value techniques to derive a Levelized Unit Energy Cost in a particular year's dollars (OPG's 3.5 ¢/kWh is in 2015$). Because LUEC is "levelized" and is expressed in a particular year's dollars, if expressed in dollars of a future year, say 2020 or 2035, the LUEC would appear to be higher, but is the same number, simply expressed in a future year's dollars.
    - The 3.9 ¢/kWh is a simple amortization which generates an even "payment" in "nominal" dollars or dollars of the year.
    - The simple amortization implicitly assumes that energy production is the same in each year of Darlington's post-refurbishment operating life. In reality, generation will fluctuate to reflect annual forecast outage patterns and the staggered return-to-service dates and out-of service dates of the units.

2. OPG's LUEC is an "after-tax" LUEC, which takes into account the impact of income tax deductions including the Capital Cost Allowance as the asset is depreciated over its life. The simple amortization does not take into account tax impacts.

ONTARIO POWER GENERATION

Updated May 22, 2014

Explanation of Levelized Unit Energy Cost (LUEC)

- LUEC is an economic measure, often used as a screening tool to facilitate consistent cost comparisons across generation options with different lives and cost characteristics
- It is generally expressed in today's dollars. LUEC is a constant number that changes over time at the rate of inflation
- It is indicative of the "levelized price" (in ¢/kWh or $/MWh) that is required for an option to achieve the target rate of return (Weighted Average Cost of Capital (WACC)) given the assumed option service life, operating pattern and incremental cost profile
- The calculation of LUEC, expressed as a mathematical equation is as follows:

$$\sum^{t} PV_{(\text{cost [\$]} \ \times \ \text{esc})} = \sum^{t} PV_{(\text{energy [MWh]} \ \times \ \text{LUEC [\$/MWh]} \ \times \ \text{cpi})}$$

where:

t = period over which costs and/or generation arises

esc = escalation index to convert to dollars of the year

cpi = consumer price index or inflation index

PV = present value at a specified discount rate, usually at WACC

Hence:

$$\text{LUEC} = \frac{\sum^{t} PV_{\text{cost [\$]} \ \times \ \text{esc}}}{\sum^{t} PV_{(\text{energy [MWh]} \ \times \ 1\$/\text{MWh} \ \times \ \text{cpi})}}$$

- For the purposes of economic comparisons, "Going Forward" (i.e. excluding sunk costs) LUECs should be used.

Prepared by:

Investment Planning
Ontario Power Generation Inc.

EB 2016-0152 Attachment 2 Page 1

		Constant	Unit	Total	Year0	Year1	Year2	Year3	Year4	Year5	Year6	Year7	Year8	Year9	Year10
Basic Project Assumptions															
a	Project Cost		$	$1,000,000	$1,000,000										
b	Energy		MWh	20000.0		2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
	Discount rate	7%													
c	Discount factor				1.000	0.935	0.873	0.816	0.763	0.713	0.666	0.623	0.582	0.544	0.508
Simple Amortization Methodology															
d	Simple amort of Project Cost		esc$	$1,423,775		$142,378	$142,378	$142,378	$142,378	$142,378	$142,378	$142,378	$142,378	$142,378	$142,378
	d = (-1)* PMT(7%, 10, a)														
e	check: PV of Simple amort	$1,000,000.00													
	e = NPV(7%, d)														
f	**Simple amort energy rate**	**$71.2**	**esc$/MWh**												
	f = d / b														
	Escalation rate	2%													
g	escalation factor				1.000	1.020	1.040	1.061	1.082	1.104	1.126	1.149	1.172	1.195	1.219
h	Simple amort energy rate		**Yr0$/MWh**		$71.19	$69.79	$68.42	$67.08	$65.77	$64.48	$63.21	$61.97	$60.76	$59.57	$58.40
	h = f / g														
LUEC Methodology															
	The above method calculates an energy rate that is constant in nominal terms but declining in constant dollar terms.														
	LUEC is the opposite: it is constant in constant dollar terms, but escalates in nominal terms.														
	To calculate LUEC, we need to calculate both numerator and denominator taking into account present value and escalation.														
i	LUEC Numerator	$1,000,000		$1,000,000	$1,000,000										
	The LUEC numerator is PV of the project cost (which in this simple example is $1,000,000)														
j	LUEC Denominator	15517.262		15517.262		1906.542	1817.451	1732.524	1651.565	1574.389	1500.819	1430.687	1363.833	1300.102	1239.350
	j = b * c * g														
	The LUEC denominator is energy adjusted for present value and escalation (since cost recovery is on a PV & escalated basis)														
k	**LUEC**	**$64.4**	**Yr0$/MWh**												
	k = I / j														
	To show that the PV of the costs recovered through LUEC equals the PV of the original project cost:														
l	LUEC		esc$/kWh		$64.44	$65.73	$67.05	$68.39	$69.76	$71.15	$72.57	$74.03	$75.51	$77.02	$78.56
	l = k * g														
	Escalate the LUEC into nominal dollars														
m	Levelized costs recovered		esc$	$1,439,521		$131,466	$134,096	$136,778	$139,513	$142,304	$145,150	$148,053	$151,014	$154,034	$157,115
	m = l * b														
n	**PV Levelized costs recovered**	**$1,000,000**													
	n = NPV(7%, m)														
	The PV of the costs recovered through LUEC equals the PV of the original project cost														

EB 2016-0152 Attachment 2 Page 2

		Constant	Unit	Total	Year0	Year1	Year2	Year3	Year4	Year5	Year6	Year7	Year8	Year9	Year10
	Basic Project Assumptions														
a	Project Cost		$	$1,000,000	$1,000,000										
b	Energy		MWh	20000.0		2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
	Discount rate	5%													
c	Discount factor				1.000	0.953	0.909	0.866	0.826	0.787	0.750	0.715	0.682	0.650	0.620
	Simple Amortization Methodology														
d	Simple amort of Project Cost		esc$	$1,288,887		$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889
	d = (-1)* PMT(7%, 10, a)														
e	check: PV of Simple amort	$1,000,000.00													
	e = NPV(7%, d)														
f	**Simple amort energy rate**	**$64.4**	**esc$/MWh**												
	f = d / b														
	Escalation rate	0%													
g	escalation factor				1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
h	Simple amort energy rate		**Yr0$/MWh**		$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44
	h = f / g														
	LUEC Methodology														
	The above method calculates an energy rate that is constant in nominal terms but declining in constant dollar terms.														
	LUEC is the opposite: it is constant in constant dollar terms, but escalates in nominal terms.														
	To calculate LUEC, we need to calculate both numerator and denominator taking into account present value and escalation.														
i	LUEC Numerator	$1,000,000		$1,000,000	$1,000,000										
	The LUEC numerator is PV of the project cost (which in this simple example is $1,000,000)														
j	LUEC Denominator	15517.262		15517.262		1906.542	1817.451	1732.524	1651.565	1574.389	1500.819	1430.687	1363.833	1300.102	1239.350
	j = b * c * g														
	The LUEC denominator is energy adjusted for present value and escalation (since cost recovery is on a PV & escalated basis)														
k	**LUEC**	**$64.4**	**Yr0$/MWh**												
	k = I / j														
	To show that the PV of the costs recovered through LUEC equals the PV of the original project cost:														
l	LUEC		esc$/kWh		$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44	$64.44
	l = k * g														
	Escalate the LUEC into nominal dollars														
m	Levelized costs recovered		esc$	$1,288,887		$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889	$128,889
	m = l * b														
n	**PV Levelized costs recovered**	**$1,000,000**													
	n = NPV(7%, m)														
	The PV of the costs recovered through LUEC equals the PV of the original project cost														

UNDERTAKING JT1.17
ATTACHMENT F

Undertaking

ED INTERROGATORY #22

According to this interrogatory response, dismantlement of the Pickering Nuclear Station cannot occur "while the irradiated nuclear fuel is being contained within the station. Therefore, under an immediate dismantlement strategy, the physical act of dismantlement would not begin until in the order of 12 years after the station closure, in order to account for cooling of fuel in wet bays and the full emptying of those wet pays into dry storage containers."

(a) Is the Darlington Re-Build proceeding while nuclear fuel is being contained within the Darlington Nuclear Station? If yes, why can a re-build proceed in the presence of irradiated fuel while a dismantling cannot?

(b) Please explain why immediate decommissioning is allowed in other jurisdictions and not in Ontario? Is there anything unique about the technology used by OPG that would prevent immediate decommissioning?

Response

(a) The refurbishment of a reactor, such as Darlington, is fundamentally different than decommissioning. Decommissioning involves large scale demolition of structures which surround the reactor and the wet bays in which the used fuel is stored. Demolition of facilities and structures adjacent to the wet bays while the irradiated nuclear fuel was still present would represent risk of compromising structural integrity thereby restricting conventional methods of dismantlement and increases cost significantly. By comparison, refurbishment does not involve removal of safety related plant structures.

(b) Immediate decommissioning is not prohibited in Ontario or Canada. OPG has chosen deferred decommissioning as the best approach to minimize workers exposure to radiation. This approach is consistent with international practice. There is nothing unique about OPG's technology that would prevent immediate decommissioning. The only limitations to immediate dismantling are the safety of fuel stored in the wet bays as described in part (a) above.

UNDERTAKING JT1.17
ATTACHMENT G

Undertaking

ED INTERROGATORY #28

1. With respect to the first 3 columns in (b) why does Pickering's estimated available capacity in 2020 (3094 MW) equal its installed capacity? That is, why does the IESO assume that the expected forced outage rate is zero? For each column and each year, please state the impact in MW of the expected forced outage rate on Pickering's available capacity at the time of the system peak.

2. With respect to the response to (d), please also quantify the impact of Pickering's extended operation on imports & exports for each year (another form of avoided generation).

3. With respect to sub-question (e), the IESO has misinterpreted ED's question. ED is not seeking Pickering's actual forced outage rate in 2014, but rather the forced outrage rates that the IESO assumed for Pickering when forecasting how much of its capacity would be available at the time of Ontario's system peak for each year of its analysis. Please ask the IESO to provide this information.

Response

The following response has been prepared by the IESO.

1. The Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for within the reserve margin as well as in power system production simulation analysis.

2. Please see table below for the impact of Pickering extended operation on electricity imports and exports.

	Change in Energy (GWh)			
	Case with +65 TWh of Pickering Production		Case with +62 TWh of Pickering Production	
	Imports	Exports	Imports	Exports
2015	0	0	0	0
2016	0	0	0	0
2017	237	-271	237	-271
2018	264	-665	234	-637
2019	324	-932	335	-816
2020	687	-1,740	854	-1,982
2021	-6,596	5,961	-6,447	5,706
2022	-6,610	8,035	-6,392	7,625
2023	-4,667	5,332	-4,400	4,984
2024	-4,851	7,458	-4,708	7,248

3. The IESO accounted for both forced and planned outages in its analysis. The tables below summarize forced outage and planned outage rates used.

For the case with +65 Twh of Pickering Production with the extension

Pickering to 2020

Forced Outages	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	n/a	n/a	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	n/a	n/a	n/a	n/a

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	143	69	119	43	n/a	n/a	n/a	n/a
P4	108	57	121	-	40	n/a	n/a	n/a	n/a
P5	-	145	-	109	-	n/a	n/a	n/a	n/a
P6	-	121	-	131	-	n/a	n/a	n/a	n/a
P7	118	-	122	-	-	n/a	n/a	n/a	n/a
P8	143	-	117	-	40	n/a	n/a	n/a	n/a

Pickering to 2022/2024

	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	7.2%	7.2%	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.5%	5.0%

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	192	43	129	43	97	43	-	-
P4	108	43	131	-	111	34	42	-	-
P5	-	148	-	182	-	147	-	101	-
P6	-	158	-	207	-	151	-	99	-
P7	118	-	221	-	106	34	140	-	-
P8	143	-	137	-	157	34	141	-	40

For the case with +62 Twh of Pickering Production with the extension

Pickering to 2020

Forced Outages	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	n/a	n/a	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	n/a	n/a	n/a	n/a

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	143	69	119	43	n/a	n/a	n/a	n/a
P4	108	57	121	63	69	n/a	n/a	n/a	n/a
P5	-	145	-	109	-	n/a	n/a	n/a	n/a
P6	-	121	-	131	-	n/a	n/a	n/a	n/a
P7	118	-	122	-	-	n/a	n/a	n/a	n/a
P8	143	-	117	-	40	n/a	n/a	n/a	n/a

Pickering to 2022/2024

	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1 & P4	7.0%	7.0%	7.1%	7.1%	7.2%	7.2%	7.2%	n/a	n/a
P5 - P8	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.5%	5.0%

Planned Outages (Days)	2016	2017	2018	2019	2020	2021	2022	2023	2024
P1	34	192	43	128	43	138	43	-	-
P4	108	43	130	43	153	30	83	-	-
P5	-	148	-	182	-	168	-	135	-
P6	-	158	-	207	-	167	-	134	-
P7	118	-	221	-	127	30	160	-	-
P8	143	-	137	-	177	30	161	-	75

4. As a starting point, the IESO adopted OPG's cost estimates in the IESO assessment of Pickering extended operations. The IESO subsequently considered the potential for higher costs/lower Pickering performance by way of sensitivity analysis.

UNDERTAKING JT1.17
ATTACHMENT H

Undertaking

ED INTERROGATORY #29

1. With respect to response (b), for each year please state how much of the difference in MWs between Pickering's "installed" and "available capacity" is due to expected forced outages.

2. Part (d) requested the avoided generation that the IESO estimates would be caused by Pickering operating to 2022/2024. The IESO stated as follows: "Not applicable, as the simulation run of Pickering operates to 2020 is not available." This response does not explain why a response could not be calculated or provided. Please provide a response to that part of the interrogatory.

3. Part (e) requested the IESO's *current* forecast of the Pickering forced outage rate from 2016 to 2024. The reference provided in response does not include that information. Please provide the requested information.

4. No response was provided to part (f). Please provide a response.

5. No response was provided to part (l). Please provide a response. This is relevant. If Ontario's incremental peaking requirements, assuming Pickering is not extended, have changed, then this will impact the economics of the proposed Pickering extension. Whether or not a Pickering simulation is available, the IESO will have up-to-date estimates of our incremental capacity requirements if Pickering is not extended.

6. No response was provided to part (m). Please provide a response. The IESO analysis has assumed that the cost of the replacement capacity is equal to the cost of building new gasfired peaker plants. But it is highly relevant to know if there are lower cost options to meet our capacity needs.

7. The last line of the interrogatory asked that the IESO "please state your methodology for calculating Pickering's available capacity (MW) at the time of Ontario's peak demand." No response was provided to this part of the interrogatory. Please provide a response.

Response

The following response has been prepared by the IESO. OPG has inserted evidence references in square brackets.

1. As indicated earlier in ED IR #28 [Ex. JT1.17(g)] part 1, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. The forced outage rate is accounted for, however, and influences the size of the required

reserve margin. The forced outage rate is also accounted for in production simulation analysis.

2. The change in generation production as a result of Pickering Extended Operations is summarized in the tables below.

   The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 65 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	**332,680**	**274,744**	**470,923**	**456,172**	**-6,756,544**	**-6,473,855**	**-4,730,629**	**-4,167,951**
Hydroelectric	0	0	**19,589**	**61,943**	**99,731**	**303,070**	**-373,796**	**-183,024**	**-106,101**	**-228,202**
Wind	0	0	**30,636**	**19,706**	**21,952**	**213,356**	**-42,286**	0	0	**-11,202**

   The following table summarizes the avoided generation (MWh) by fuel type as a result of Pickering's extended operation in the plus 62 TWh of Pickering Production case. Blue and positive numbers represent increase in production and red and negative numbers represent decrease in production as a result of Pickering's extended operation.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gas	0	0	**332,680**	**209,640**	**351,228**	**763,473**	**-6,424,056**	**-6,111,821**	**-4,473,760**	**-4,108,400**
Hydroelectric	0	0	**19,589**	**61,943**	**83,710**	**287,308**	**-357,001**	**-182,338**	**-99,313**	**-219,580**
Wind	0	0	**30,636**	**19,706**	**16,050**	**140,642**	**-28,515**	0	0	**-11,202**

   Please see response to ED IR #28 [Ex. JT1.17(g)] part 2 for the impact of Pickering extended operation on electricity imports and exports.

3. Forced outage and planned outage rates assumed in the IESO study are summarized in the response to ED IR #28 [Ex. JT1.17(g)] part 3.

4. See response to part 7 of this interrogatory [Ex. JT1.17(g)].

5. The replacement capacity assumed is assumed to be equivalent to the change in capacity requirements between Pickering operation to 2020 and 2022/2024. These are summarized in the table below.

	Increase in Capacity Requirements Pickering to 2020 relative to 2022/2024 (MW)
2015	0
2016	0
2017	0
2018	0
2019	0
2020	0
2021	2,316
2022	2,301
2023	2,064
2024	1,090

100% of this capacity was assumed to be replaced. This represents the capacity that would need to be replaced to meet NPCC resource adequacy criteria.

6. The cost of replacement capacity is benchmarked to be that of a new-build SCGT at $130/kW-yr. Gas is used as a proxy resource here. This would be the benchmark price for other resources such as demand response or firm capcity imports.

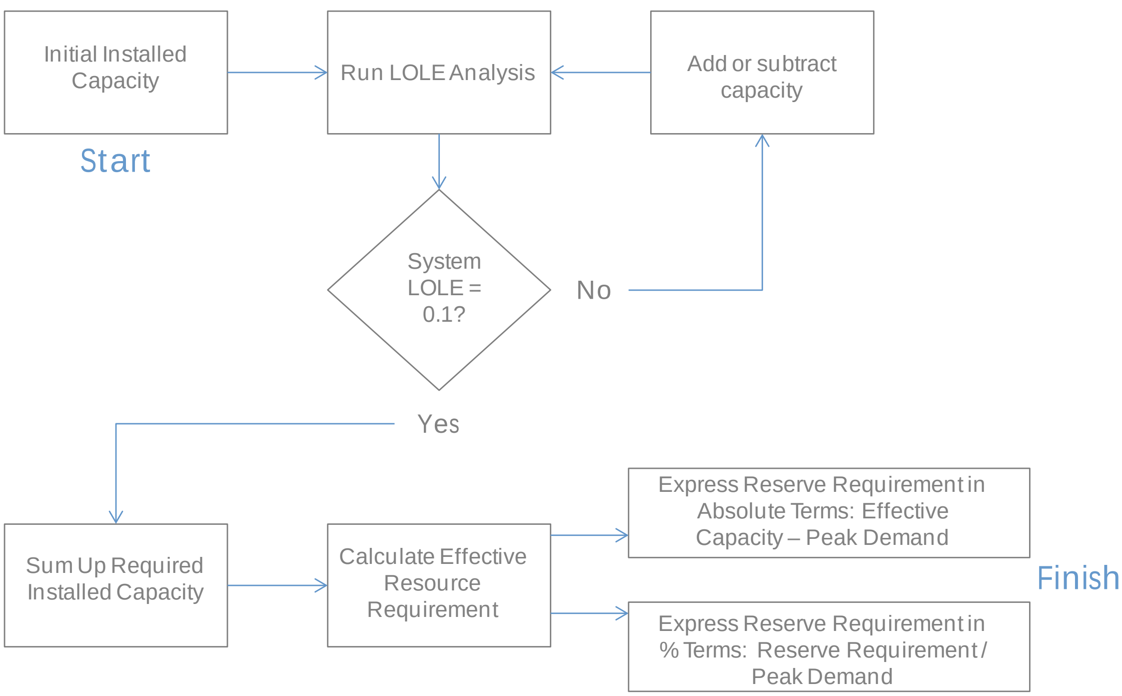
7. The “capacity contribution” or “effective capacity” of a supply resource is an approximation of its power output capability during peak demand periods and can be expressed as a percentage of a resource’s installed capacity. Capacity contributions vary among resource types and can be estimated through a variety of methods.

   For planning purposes, the IESO estimates the capacity contributions through a variety of approaches, including by incorporating values submitted to the IESO by electricity generators, analyzing historical generator performance and using statistical methods to assess resource contributions during various percentiles of peak demand or other hours.

   Data and methods used to estimate capacity contributions evolve over time as more data is acquired and as methodological improvements are made. The following table provides indicative overall values, which in practice differ by generator, location and season. More information about these values is available at the Ontario Planning Outlook at http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx:

	Indicative Capacity Contribution (% of Installed Capacity Available at Time of Peak Demand)	
	At Summer Peak	At Winter Peak
Nuclear	99%	90%
Natural Gas	89%	95%
Waterpower	71%	75%
Bioenergy	89%	89%
Wind	11%	28%
Solar PV	33%	5%
Demand Response	83%	66%

Capacity contribution estimates are used in two main ways: they are part of the iterative loss of load expectation and resource requirement assessment process shown in the schematic below and they are used in a variety of supply-demand balance visualizations to allow for approximate but efficient portrayal.



UNDERTAKING JT1.17
ATTACHMENT I

Undertaking

ED INTERROGATORY #34

1. With respect to the numbers in Section T4 for the years 2021 to 2024 inclusive: please provide for each year the IESO's estimate of: a) Pickering's installed capacity; and b) available capacity at the summer peak. Please describe the IESO's methodology and show its calculations for calculating the difference between installed and available capacity.

2. With respect to the load forecasts shown in Section T3: are any of them consistent with the IESO's MARS program? If no, please provide the MARS load forecasts for these years. [Note: The IESO uses General Electric's Multi-Area Reliability Simulation (MARS) program to derive its load forecast to estimate its reserve margin requirements. See IESO, *Ontario Reserve Margin Requirements 2016 – 2020: Issue 1.0* (December 21, 2015).]

3. Please provide a response to part (b). The IESO outlined a methodology but did not provide an answer.

Response

The following response has been prepared by the IESO. OPG has inserted the evidence reference in square brackets.

1. The following table summarizes Pickering's total installed capacity (MW) in different scenarios:

	Case with +65 TWh of Pickering Production, Pickering to 2020	Case with +65 TWh of Pickering Production, Pickering to 2022/2024	Case with +62 TWh of Pickering Production, Pickering to 2020	Case with +62 TWh of Pickering Production, Pickering to 2022/2024
2015	3094	3094	3094	3094
2016	3094	3094	3094	3094
2017	3094	3094	3094	3094
2018	3094	3094	3094	3094
2019	3094	3094	3094	3094
2020	3094	3094	3094	3094
2021	0	3094	0	3094
2022	0	3094	0	3094
2023	0	2064	0	2064
2024	0	2064	0	2064

As a starting point, the Pickering capacity that is available at the time of peak demand is assumed to be the installed capacity, provided that it is not on planned outage or forced outage or in a derated state. IESO's assessment of the overall performance of Pickering further units includes accounting for forced outage and planned outage rates and derates, which are considered in reserve margin calculations and power system production simulations.

2. Yes. The forecasts are consistent, but are not identical; this reflects different vintages of production. For example, the more recently produced demand outlooks contained in the Ontario Planning Outlook depict ranges rather than a single projection.

3. Per IR 34 [Ex. L-6.5-7 ED-34] response (b), the total amount of incremental firm capacity (MWs) that can be imported into Ontario is a function of: import capacity (the physical wires), real-time system constraints (physical constraints based on real-time internal and external supply/demand balances and transmission limitations) and economics (cost). The current physical import capacity is up to approximately 6,900 MW. This represents a theoretical level that could be achieved only with a substantial reduction in generation dispatch in the West and Niagara transmission zones. In practice, the generation dispatch required for high import levels would rarely, if ever, materialize. Therefore, at best, due to internal constraints in the Ontario transmission network in conjunction with external scheduling limitations, Ontario has an expected coincident import capability of approximately 5,200 MW.

UNDERTAKING JT1.17
ATTACHMENT J

Undertaking

ED INTERROGATORY #36

With respect to Table 1, were any "decrements" made to take into account the expected forced outage rates for Darlington and Pickering? If yes, please provide the MW adjustments for each station for each year.

If no forced outage rate adjustments are made, please reconcile this fact with their *Ontario Reserve Margin Requirements: 2016 – 2020* report which states: "Equivalent forced outage rates (EFOR) of existing units are derived based on analysis of a rolling five-year history of actual forced outage data." [p. 10]

Response

The following response has been prepared by the IESO. OPG has inserted the evidence reference in square brackets.

Yes – both forced and planned outages are accounted for by the IESO in its assessment of Pickering extended operations. Forced and planned outage rates assumed are summarized in the response to ED IR#28 [Ex. JT1.17(g)] part 3.

UNDERTAKING JT1.17
ATTACHMENT K

Undertaking

ED INTERROGATORY #13
OPG has not provided an estimate of the probability that some or all of the steam generators will need to be replaced; nor has it provided its best estimate of the cost of replacing them. The fact that OPG believes that the generators will operate reliably does not mean that there is *no* probability that it will turn out that they will need to be replaced. Nor does it mean that the question is irrelevant or need not be answer. Please provide the information requested in this interrogatory.

Response

OPG declines to respond to this request on the basis of relevance. As OPG has determined not to include steam generator replacement within the scope of the DRP and is not seeking funding in this application to replace the steam generators, the information is not relevant to the issues before the OEB. In any event, OPG has already provided a full response to ED 13 in Ex. L-4.3-7 ED-13. This response incorporates by reference the responsive material in that OPG had previously provided in EB-2010-0008.

UNDERTAKING JT1.17
ATTACHMENT L

Undertaking

ED INTERROGATORY #30

This interrogatory requested that the IESO recalculate its cost-benefit analysis of Pickering Extended Operations based on its best *current* estimates of the key variables listed in the interrogatory. The IESO stated that it has not updated its assessment. That is not a justification for not doing so. The requested information is highly relevant. We ask that the requested information be provided.

Response

OPG declines to respond to this request on the basis of relevance. In its Decision in EB-2013-0321 approving expenditures for Pickering Continued Operations, the OEB discussed the fact that the OPA found that project to have positive benefits (see page 51). On this basis, OPG determined that the OEB and the parties could find the IESO's analysis similarly helpful in reviewing the costs of Pickering Extended Operations and included both the IESO's initial (March 9, 2015) and follow-up (November 4, 2015) analyses as an attachment to OPG's evidence (Ex. F2-2-3, Attachment 1). As the IESO has indicated that it has not performed any subsequent analysis, there is nothing more to produce. The fact that Environmental Defence would like the IESO to perform further updates does not make this information necessary or relevant to the OEB's consideration of the costs to extend Pickering Operations.

UNDERTAKING JT1.17
ATTACHMENT M

Undertaking

ED INTERROGATORY #33
This interrogatory requested a comparison of Pickering Extended Operations versus a shutdown in August 31, 2018. No response was provided. Please provide a response. August 31, 2018 is a highly relevant date for comparison purposes. Pickering cannot be shut down before that date, which is when the Clarington Transformer Station will be built. But after that date, Pickering is just one of a number of options to meet Ontario's electricity supply. At that point, OPG should not be paid more for the power from Pickering than the cheapest alternative, which could be considered to be the "market rate." After that date it is important to know what the lowest cost alternative is. Environmental Defence would argue that OPG should not be paid any more than the lowest cost alternative.

Response

OPG declines to respond to this request on the basis of relevance. The comparison requested is not relevant to the issue before the OEB, which is the establishment of payment amounts for OPG and not whether Pickering should continue to operate (see references in Undertaking Response JT1.17n). Furthermore, as Mr. Blazanin explained during the technical conference: "The CNSC board has already approved operation of Pickering to 247,000 effective full power hours on our fuel channels, which is the life limiting major component. That would take most units into the 2020 time frame already." (Technical Conference Transcript V. 2, page 82, lines 20-24). Thus as a practical matter, there is no basis for assuming an August 31, 2018 shut-down date as requested in the interrogatory.

UNDERTAKING JT1.17
ATTACHMENT N

Undertaking

ED INTERROGATORY #35

Please answer this interrogatory. The IESO states that its contingency planning is still ongoing, but that is not a reason for not providing its best possible answers to our questions now.

Response

OPG declines to respond to this request on the basis of relevance. As the IR answer indicates, the requested information is not available because the IESO is in the process of developing it. Moreover, the requested information is not relevant to deciding the issue before the OEB regarding the cost of Pickering Extended Operation. As the OEB has recognized in several prior decisions, the purpose of this proceeding is to establish payment amounts and not to decide system planning issues or determine whether specific generation facilities should continue to operate.[1]

[1] See EB-2007-0905, Decision with Reasons, page 28; EB-2010-008, Decision with Reasons, page 51; EB-2013,-0321 Decision on Issues List, June 4, 2014, page 3 “The Board agrees with OPG that generation planning is not within the scope of this proceeding.”

UNDERTAKING JT1.17
ATTACHMENT O

Undertaking

ED INTERROGATORY #38
Please provide a copy of the electricity agreement with the Government of Quebec as requested. The IESO provided a link to a news release, not the agreement as requested.

Response

OPG does not have the agreement and does not believe it is relevant to any issue before the OEB.

As legal counsel for OPG explained during the technical conference: “The view would be that with respect to the comparison of alternatives, particularly whether it's hydro from Quebec or otherwise, that the consideration of those alternatives goes to the establishment of need or the alternatives within the context of a system planning, and that, as the Board has previously held in other proceedings, is not within their scope. In actual fact, their scope relates to those of an implementation of rates and the acceptance of any costs associated with execution of the project.” (Technical Conference Transcript V. 2, page 3, lines 14-23).

As legal counsel for OPG further explained: “the agreement with Quebec is, I think, fully within the system planning mode and authority of the IESO and it relates to that form of alternative generation. It's not related to the costs of completing the extended ops, which is truly the issue before this proceeding. So it's just simply not relevant.” (Technical Conference Transcript V. 2, page 17, lines 9-14).

UNDERTAKING JT1.17
ATTACHMENT P

Undertaking

ED INTERROGATORY #39
This interrogatory requested a comparison of the net benefits of continuing to operate Pickering until 2022/2024 versus a Pickering shutdown in August 31, 2018, with replacement power to come from a combination of the lowest cost options including the maximum possible electricity imports from Quebec. This was not done. The IESO stated that hydro power from Quebec cannot fully replace Pickering and that the IESO's analysis is already based on "the next least-cost alternative." However, the IESO's analysis is based on obtaining all the power from one source – gas fired generation, rather than a combination of lowest cost sources including increased power imports. Please provide a response based on a combination of the lower cost sources.

Please also assume that replacement electricity is not needed to replace electricity that would be exported (i.e. replacement power is only required to meet Ontario's actual needs).

Response

OPG declines to respond to this request on the basis of relevance. As explained in JT1.17(n), the purpose of this proceeding is not to consider system planning or to determine whether Pickering should continue to operate. Furthermore, as noted in JT1.17(m), as a practical matter, there is no basis for assuming an August 31, 2018 shut-down date.

UNDERTAKING JT1.18

Undertaking

TO PROVIDE THE OPG POSITION ON MONTHLY AND QUARTERLY REPORTING OF THOSE FIGURES

Response

The context for this undertaking is shown in the Technical Conference transcript of November 14, 2016, p. 96, line 23 through to p. 100, line 13 and with reference to OPG's responses to Ex. L-4.3-7 ED-006 and Ex. L-4.3-7 ED-009 with respect to Unit 2 costs and public reporting on the Darlington Refurbishment Program (DRP) respectively.

OPG has considered the request and will issue public reporting on the status of the DRP and specifically on Unit 2 safety, quality, cost performance and schedule performance on a quarterly basis shortly after the issuance of its quarterly Management Discussion and Analysis (MD&A) and external financial reports.

OPG will also issue frequent updates on the status of the project on OPG's website, with the current plan being monthly.

In addition, as discussed in Ex. L-10.4-1 Staff-223, OPG proposes to report annually to the OEB on the DRP performance measures set out in Ex. D2-2-9, pp. 9-10, in conjunction with the reporting on the hydroelectric and nuclear performance measures set out in Ex. A1-3-2, pp. 41-42.

UNDERTAKING JT1.19

Undertaking

FOR D2, 28, ATTACHMENT NUMBER 1, PAGE 29, TO PROVIDE A UNIT BREAKOUT OF THE CUMULATIVE SPEND

Response

Life-to-date costs to September 2016 are $2,900 million. The unit breakout is as follows:

Unit/Category	LTD Cost ($M)	Comments
Unit 2	1,881	Includes Definition Phase costs
Unit 3	26	Primarily Engineering for the T/G controls
Unit 1	0	
Unit 4	0	
Early In Service Projects	972	Including FIP/SIO
Project OM&A	20	
Total Life-to-Date	**2,900**	**To September 2016**

UNDERTAKING JT1.20

Undertaking

TO RECALCULATE IR 3 AND 4 BASED ONLY ON FUTURE COSTS, OR WHY OPG WILL NOT ANSWER.

Response

Please note that OPG's response to this undertaking should be read in conjunction with the responses to interrogatory L-4.3-7 ED-003 and interrogatory L-4.3-7 ED-004 with particular emphasis on the qualifications OPG has noted in preparing these scenario assessments.

This response is an update to interrogatories L-04.3-7 ED-003 and L-04.3-7 ED-004 to apply the cost overruns scenarios to only the future costs. These calculations assume all costs to date are on plan with respect to the cost incentive and disincentive calculations.

As in interrogatories L-04.3-7 ED-003 and L-04.3-7 ED-004, OPG has provided the results of pro-rating OPG's RQE estimate on costs remaining to be spent by: a) 25%; and, d) 100%.

Update to Interrogatory L-04.3-7 ED-003

The calculated percentage of these cost overruns that would be passed on to OPG when the cost overrun percentages are applied only to the future costs are: a) 85% of the 25% cost overrun; d) 86% of the 100% cost overrun.

Update to Interrogatory L-04.3-7 ED-004

When the cost overrun percentages are applied only to the future costs:

a) For the 25% cost overrun scenario, the total cost of the DRP mathematically evaluates to $14.7B

b) For the 100% cost overrun scenario, the total cost of the DRP mathematically evaluates to $20.6B.

The detailed cost breakdowns for the above two scenarios, in a similar format to Chart 4 in Ex. D2-2-3 p. 14 are provided in Attachment 1 (Attachment 1 contains confidential information).

Attachment to L-04.3-7 ED-004 (includes summary calculations for L-04.3-7 ED-003) - Amended for JT1.20

Cost Overrun Scenarios

2015$M (except for Interest and Escalation line item)

				ED-004/ JT-1.20					ED-003	ED-004/ JT-1.20					ED-003
				1.25	25% Cost Growth					2	100% Cost Growth				
Major Category		**Category/ Contract Type**	**RQE Base Costs (1)**	**Base cost + % Increase on Remaining Costs**	**Cost Variance on Remaining Costs**	**Impact to Contractor**	**Impact to OPG**	**Actual Cost to OPG**	**Proportion of Increase paid by OPG**	**Base cost + % Increase on Remaining Costs**	**Cost Variance on Remaining Costs**	**Impact to Contractor**	**Impact to OPG**	**Actual Cos to OPG**	**Proportion of Increase paid by OPG**
Retube Feeder Replacement		OPG Project Management & Oversight Costs	167	191	24		24	191		265	98		98	265	
	Contractor Costs	Definition Phase Target Price (Incl RWPB)	185	186	1	0	1	186		190	5	0	5	190	
		Definition Phase Fixed Fee	74	76	2	2	0	74		83	10	10	0	74	
		Definition Phase Fixed Fee Incentive/ Disincentive		0		0	0	0		0		0	(0.400)	(0)	
		Execution Phase Target Price	1,667	2,076	409	0	409	2,076		3,301	1,634	0	1,634	3,301	
		Execution Phase Fixed Fee	492	613	121	121	0	492		974	482	482	0	492	
		Execution Phase Fixed Fee Incentive/ Disincentive		0		67	(67)	(67)		0		236	(236)	(236)	
		Mock-up Fixed Price	38	38	0	0	0	38		38	0	0	0	38	
		Non-target Reimbursable Costs	6	8	2	0	2	8		12	6	0	6	12	
		Tooling Fixed Price	375	377	2	2	0	375		383	8	8	0	375	
		OSM with Fee(estimate)	579	704	125	0	125	704		1,078	499	0	499	1,078	
		Goods with Fee(estimate)	48	60	12	0	12	60		96	48	0	48	96	
Fuel Handling/ Defueling		OPG Project Management & Oversight Costs	49	58	9		9	58		85	36		36	85	
	Cont. Costs	Defueling - Eng Services (Fixed/Firm Price)	16	16	0	0	0	16		16	0	0	0	16	
		Defueling - Eng Services (Misc Reimbursable)	7	7	0	0	0	7		7	0	0	0	7	
		Fuel Handling (ESMSA - see assumptions)	126	155	29	[redacted]				242	117	[redacted]			
Steam Generators		OPG Project Management & Oversight Costs	13	15	2		2	15		22	9		9	22	
	Contractor Costs	Fixed Price	[redacted]							[redacted]					
		Target Price													
		Target Price Fixed Fee													
		Target Price Fixed Fee Incentive/ Disincentive							73%						74%
		SS&E & Reimbursable													
		SS&E Incentive/Disincentive													
Turbine Generator		OPG Project Management & Oversight Costs	41	48	7		7	48		69	28		28	69	
	Contractor Costs	ESES - Fixed/ Firm Cost - Equipment Supply	257	299	43	43	0	257		428	171	171	0	257	
		ESES - Target Cost Installation & Static Commissioning	38	48	10	0	10	48		77	38	0	38	77	
		ESES - Target Cost - Incentive/ Disincentive		0		5	(5)	(5)		0		19	(19)	(19)	
		ESES - Target Cost - Dynamic Commissioning	14	17	3	0	3	17		28	14	0	14	28	
		ESES - Target Cost - Incentive/ Disincentive		0		2	(2)	(2)		0		7	(7)	(7)	
		ESES - Reimbursable (no markup)	28	33	5	0	5	33		47	19	0	19	47	
		EPC - Definition Phase Target Cost	21	22	0	0	0	22		23	2	0	2	23	
		EPC - Definition Phase Fixed Fee	13	13	0	0	0	13		14	1	1	0	13	
		EPC - Definition Phase Fixed Fee Incentive/ Disincentive		0		0	0	0		0		0	(0)	(0)	
		EPC - Execution Phase Target Cost	161	201	39	0	39	201		318	157	0	157	318	
		EPC - Execution Phase Fixed Fee	53	66	13	13	0	53		104	52	52	0	53	
		EPC - Execution Phase Fixed Fee Incentive/ Disincentive		0		7	(7)	(7)		0		25	(25)	(25)	
		EPC - Dynamic Commissioning Work (Trades)	2	3	1	0	1	3		5	2	0	2	5	
		EPC - Goods	5	6	1	0	1	6		10	5	0	5	10	
		EPC - Reimbursable Costs with no-markup	11	14	3	0	3	14		23	11	0	11	23	
Balance of Plant		OPG Project Management & Oversight Costs	183	213	30		30	213		304	122		122	304	
		Contractor Costs (mainly ESMSA)	784	933	149	[redacted]				1,382	598	[redacted]			
F&IP & SIO Projects		Facility and Infrastructure Projects (mainly ESMSA)	640	655	15					699	59				
		Safety Improvement Opportunities (mainly ESMSA)	205	239	34					239	34				
Functions		Project Execution	322	395	73		73	395		614	293		293	614	
		Contract Management	52	62	10		10	62		92	40		40	92	
		Engineering	283	330	47		47	330		471	188		188	471	
		Managed Systems Oversight	41	47	6		6	47		66	25		25	66	
		Planning & Controls	136	150	14		14	150		191	54		54	191	
		Nuclear Safety	83	94	11		11	94		127	44		44	127	
		Program Fees & Other Support	341	413	72		72	413	100%	630	290		290	630	100%
		Supply Chain	86	103	17		17	103		155	69		69	155	
		Work Control	80	96	16		16	96		144	65		65	144	
		Operations and Maintenance	805	984	179		179	984		1,523	718		718	1,523	
		Early Release 3	102	102	0		0	102		102	0		0	102	
		Early Release 4	7	7	0		0	7		7	0		0	7	
Contingency			1,706	1,706	0		0	1,706	N/A	1,706	0		0	1,706	N/A
Sub Total			**10,429**	**11,987**	**1,557**	**288**	**1,269**	**11,699**		**16,556**	**6,127**	**1,114**	**5,013**	**15,442**	
Interest & Escalation ($M)			2,371	2,799	429		429	2,799	100%	4,057	1,686		1,686	4,057	100%
Total			**12,800**	**14,786**	**1,986**	**288**	**1,698**	**14,498**	**85%**	**20,613**	**7,813**	**1,114**	**6,699**	**19,499**	**86%**

Notes and assumptions:

1. Based on OPG's Release Quality Estimate (RQE). All numbers except interest and escalation are in 2015$.
2. These are illustrative examples; assumption is that all contractor incentives/disincentives and performance fee mechanisms are applicable.
3. Cost overrun factors are modelled based on remaining to go costs only.
4. Cost overrun factors are not applied to contingency.
5. RFR contract costs are as per Ex. D2-2-3, pp. 10 and 11.
6. De-fuelling contract is mainly fixed/ firm price. Reimbursable fixed fees are capped for certain costs; however, this was not incorporated into the calculations due to lack of materiality.
7. Steam Generator contract includes fixed/ firm component, along with target cost with fixed fee at risk and Support Services and Equipment cost with fee at risk.
8. For work bundles that are mainly under ESMSA contracts (e.g. BOP, FH, FIP, SIO), it was assumed, for simplicity, that the increase is caused by the contractor; therefore, the cost to OPG is [redacted] of the cost overrun (performance fee of [redacted] withheld).
9. For simplicity, for all of the larger target cost contracts, a 20% cost disincentive was applied above any neutral band specified in the contracts. The actual percentage is calculated using a graded approach.
10. For simplicity, interest and escalation were pro-rated.

UNDERTAKING JT1.21

Undertaking

TO PROVIDE THE MOST RECENT COMPLETE RISK REGISTRY.

Response

The current risk register for the Darlington Refurbishment Program (DRP) was filed at L-4.3-15 SEC-026, Attachment 4. Upon review, it was noted that this risk register omitted 5 risks associated with Human Performance and the Pre-requisite Program. These additional risks are provided in Attachment 1. Together with Attachment 4 at L-4.3-15 SEC-026, a complete, current DRP risk register has been provided.

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 17-Nov-16 10:30 PM

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
561	Availability and Retention of Project Leadership	Risk pertains to securing and retaining project management leadership talent which could impact on our ability to execute Refurbishment.	3	Active	Candice Kay		10-Nov-16	Mitigate	16-Dec-16	4	3	3	12	3	3	3	9

Action#	Status	Action Title	Action Description	Owner	Delegate	Due Date	Comments
3290	In Progress	Succession Planning Process Improvements	Create a Projects Succession Planning Peer Team to develop succession plans for key project roles.	Candice Kay		30-Dec-16	All P1 roles complete and integrated with Nuclear Fleet Succession Plan. All P2 roles will be completed by Q4 2016.
3306	In Progress	PPR Health & Development Planning 4.4	Knowledge Management Transfer - critical for ongoing success	Candice Kay		29-Sep-17	November 9 - Focus on Knowledge Management (KM) for key roles. Designing org to support key leadership transitions (Q4 2016). Embedded into PMCD. KM plans will continue in 2017. · PPR for 2016 to be aligned with Project Excellence goals - cascade to all staff. · Staffing Plan to be approved/finalized · Project Management Capability Builder - Plan in place as per Project Management Peer Team
9157	In Progress	Staff Development	Review all IDP's to ensure development.	Candice Kay		30-Dec-16	In progress to be completed by Q4- 2016
9523	In Progress	Longevity Strategy	The project is 12 plus years and during this time we will lose critical leaders. Complete the following tasks: Redesign organization to provide ability to sustain work and to transfer knowledge. Launch PMCD to create future leaders. PDIT - Project Director In Training - to secure & retain future leaders.	Candice Kay		03-Apr-17	Redesign organization to provide ability to sustain work and to transfer knowledge. Launch PMCD to create future leaders. PDIT - Project Director In Training - to secure & retain future leaders. Comments for each of the above mentioned tasks: Q4 2016 - will be complete Target - Q1 2017 Complete

Outage Window	Window Description
083	083 - Lower Feeder Installation
118	118 - CT Install Series
119	119 - Fuel Channel Install Series

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
822	Completion of Refurbishment SIOs (Safety Improvement Opportunities)	The risk is that the 5 Safety Improvement Opportunity Projects (SIOs), which are a regulatory requirement to complete prior to starting refurbishment, are not complete and appropriate contingency plans to progress the Unit 2 refurbishment cannot be developed and negotiated with the CNSC, resulting in delays to Unit 2 execution and consumption of all the schedule contingency duration for on Unit 2.	3	Active	Art Rob	Art Rob	19-Apr-16	Avoid	15-Sep-16	3	3	5	15	1	3	5	5

Outage Window	Window Description
000	000 – No Window Related

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

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
697	Availability of OPG Support Group Resources	The risk is that there are insufficient OPG resources (Operations, Maintenance, P&M, NR Design, ...) to support the schedule, or that the level of effort has been underestimated, resulting in cost increases for augmented staff or over time to maintain or recover the schedule.	3	Active	Dragan Popovic		27-Oct-15	Monitor	30-Oct-15	3	1	1	3	3	1	1	3

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

ID	Risk Title	Risk Description	Urgency	Risk Status	Owner	Delegate	Risk Date Last Reviewed	Risk Response Type	Post Mitigation TCD	Current Probability	Current Financial	Current Schedule	Current Score	Post Probability	Post Financial	Post Schedule	Post Score
840	AISC SDC HX installation	Event: Installing the second HX during defueling Cause: SDC HX condition/reliability to support defueling Impact: prolong defuel critical path duration and interferes with pre-req's for vac dry equip & Pressure test	3	Active	Dragan Popovic	Dragan Popovic	18-Jul-16	Mitigate	30-Sep-16	2	1	4	8	2	1	3	6

Outage Window	Window Description
012	012 - Defuel Reactor
029	029 - HTS Vac Dry

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

ONTARIO POWER GENERATION

Risk Report by Project with Associated Actions

Report ID: 0707A *Tech Tips*
Report Owner: L. Greenland
Process Owner: L. Ren
Data Refreshed: 17-Nov-16 10:30 PM

876	Heightened Vendor QA Risk	NCAR 28150597-41 and SCR D-2016-08194 identified implementation weaknesses with ESMSA Vendor implementation of quality inspection aspects of their QA program. Findings suggest that additional risk based oversight should be implemented regarding in-process QA records preparation, care and control. Additionally finalize records should be sampled at a high rate, preferably prior to system turn-over. NOTE: This risk pertains to ESMSA Vendor Performance and has been replicated under RMO Risk 830 for Projects & Modifications, and 876 for Nuclear Refurbishment.	4	Active	Grant Howard	Grant Howard	04-Jul-16	Mitigate	31-Aug-16	3	3	5	15	3	3	5	15
			Outage Window		**Window Description**												
			000		000 – No Window Related												
			There are no Not Started, In Progress Actions associated with the risk.														

UNDERTAKING JT1.22

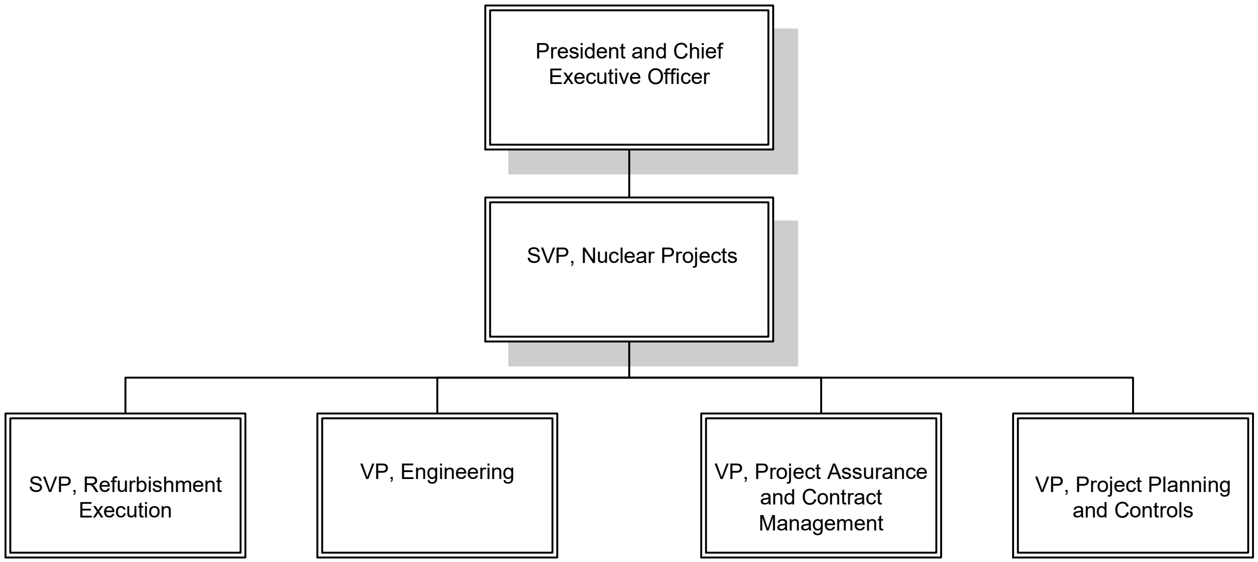
Undertaking

TO PROVIDE AN UPDATE TO THE CHART SHOWING A COUPLE LEVELS BELOW THE VP LEVEL.

Response

The context for this Undertaking was related to the organization chart OPG provided in Ex. D2-2-2 Attachment 2, p.30. The requested organization chart is provided in Attachment 1. Please note that, since the publication of the Darlington Refurbishment Charter filed in Ex. D2-2-2 Attachment 2, there have been two significant organizational changes: a) the Senior Vice President, Nuclear Projects (Mr. Dietmar Reiner), now reports directly to the Chief Executive Officer (Mr. Jeff Lyash); b) the Vice President, Projects and Modifications (Mr. Art Rob) no longer reports to Mr. Dietmar Reiner, but instead reports to the Deputy Chief Nuclear Officer; therefore Mr. Rob's organization is no longer included in the Darlington Refurbishment Program organization. These changes have been reflected in Attachment 1.

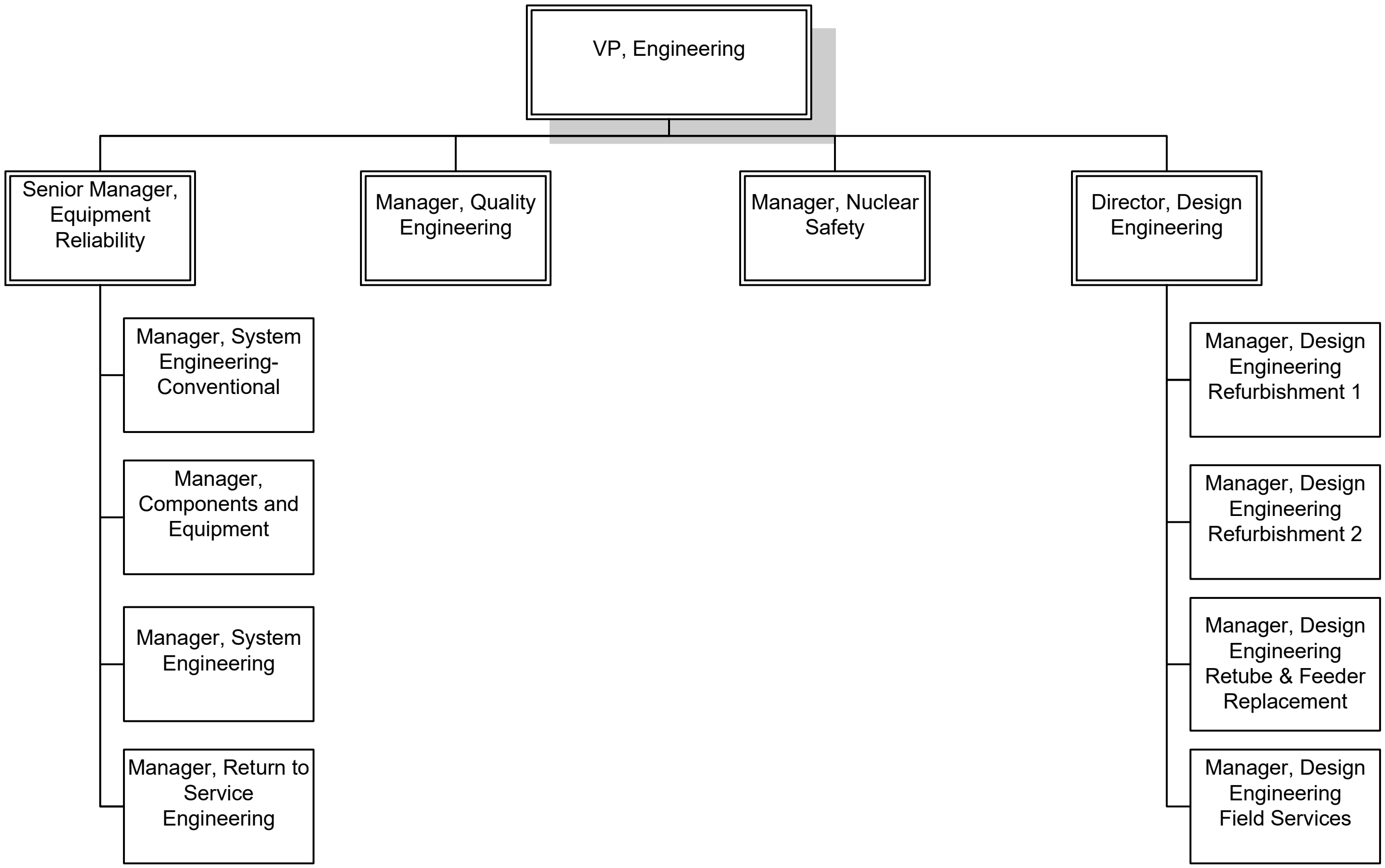
Darlington Refurbishment Organization



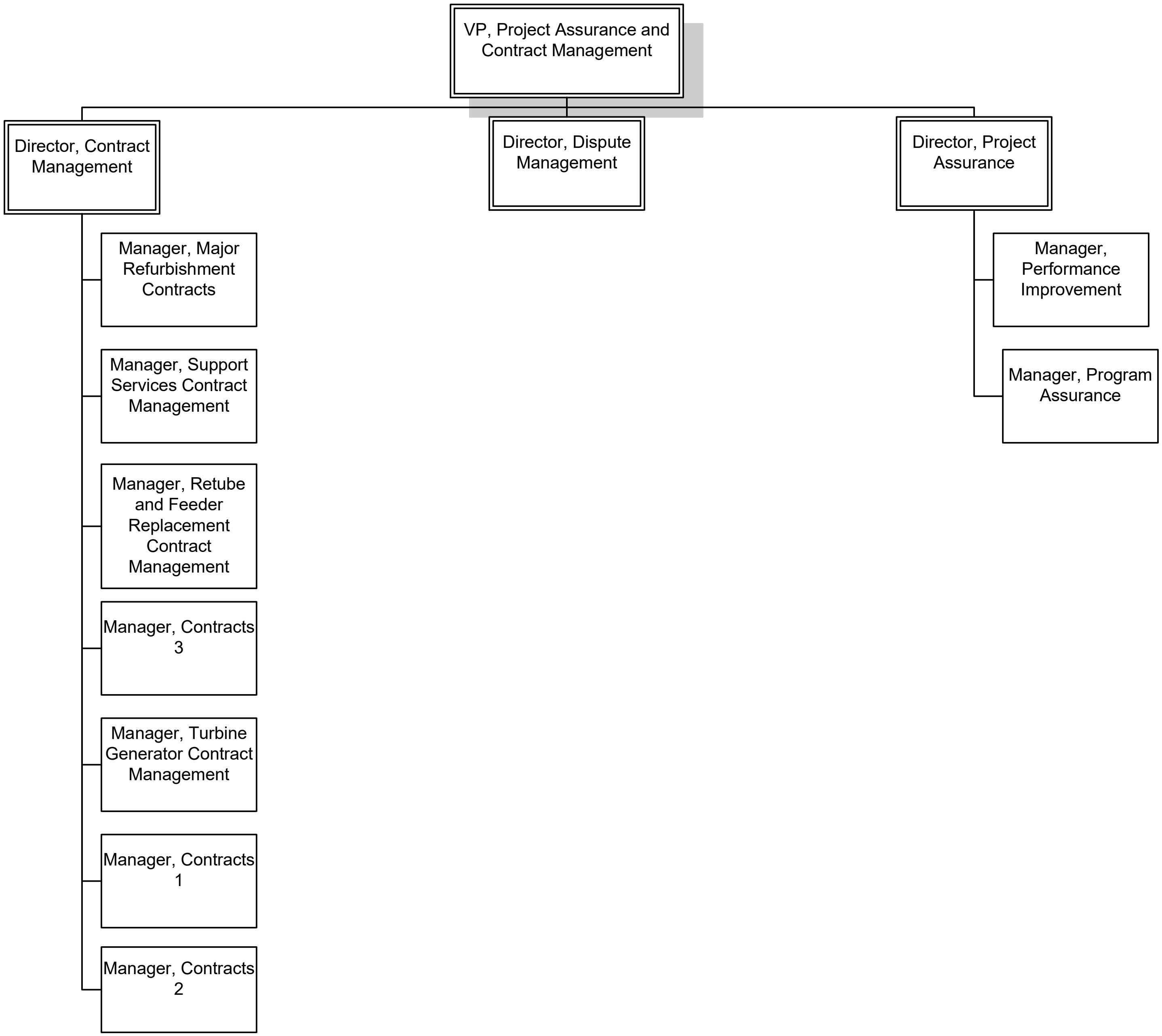
Darlington Refurbishment - Execution

- SVP, Refurb Execution
  - VP, Refurb Execution
    - Director, Construction
      - Director, Construction Oversight and Proj Field Support
        - Manager, Project Field Support
        - Manager, Retube and Feeder Replacement / Fuel Handling
        - Manager, Balance of Plant / Turbine Generators
        - Manager, Islanding/ Shut Down Layup / Steam Generators
        - Manager, Human Performance
    - Senior Director, Retube and Feeder Replacement
      - Project Director
      - Manager, Projects
      - Manager, Retube and Feeder Replacement
      - Manager, Secondment
      - Manager, Islanding
      - Manager, Tooling and Quality Control
    - Project Director, Turbine Generators
      - Manager, Turbine Generators
    - Project Director, Fuel Handling
      - Manager, Fuel Handling
      - Manager, Fuel Handling Specialized Projects
    - Project Director, Balance of Plant
      - Manager, Balance of Plant
    - Director, Project Office
      - Manager, Project Control Centre
      - Manager, Scope and Work Control Team Lead Development
      - Manager, Data Integrity
      - Manager, Station Integration
      - Manager, Retube and Feeder Replacement Integration
    - Director, Steam Generators / Shut Down Layup
      - Manager, Shut Down Layup
      - Manager, Steam Generators
    - Director, Project Parts Integration
      - Manager, Engineering Construct Procurement
    - Director, Programs Strategy
      - Manager, Program Support and Integration
      - Manager, Program Strategies and Collaboration
    - Director, Quality Management
      - Manager, Field Execution Surveillance and Reporting
    - Director, Operations and Maintenance
      - Manager, Maintenance
        - Assistant Manager- Valve Program
      - Manager, Operations and Maintenance Programs
      - Manager, Operations
        - Shift Manager, Days Preparation
        - Shift Manager, Days Execution
      - Senior Outage Manager- Return to Service
        - Manager, Return to Service
      - Manager, Chemistry and Environment

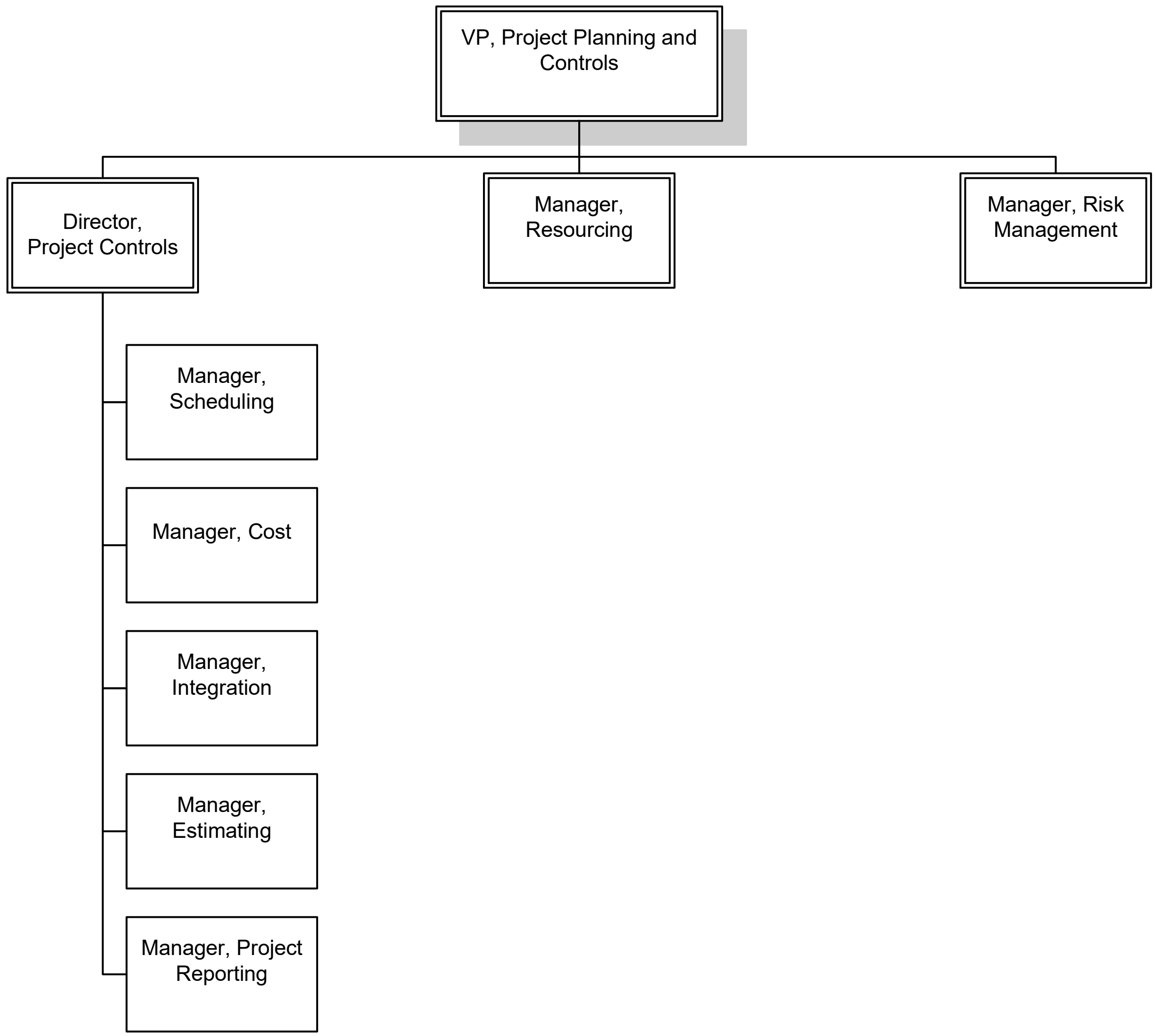
Darlington Refurbishment - Engineering



Darlington Refurbishment –
Project Assurance and Contract Management



Darlington Refurbishment – Planning and Controls



UNDERTAKING JT1.23

Undertaking

TO PROVIDE SCHEDULE 15 FROM THE SNC/AECON JOINT VENTURE EXTENDED SERVICES MASTER SERVICES AGREEMENT IF IT EXISTS, OR IF IT HASN'T BEEN DONE, TO EXPLAIN WHY.

Response

Schedule 15 of the Extended Services Master Services Agreement (ESMSA) between OPG and the SNC/AECON Joint Venture (filed at Ex. D2-2-3, Attachment 10) has not been developed as there have not been any secondments undertaken to date pursuant to section 3.2(f) of the ESMSA.

UNDERTAKING JT1.24

Undertaking

WITH RESPECT OF THE SCOPE OF WORK THAT MS. GALLOWAY HAD PERFORMED IN THIS PROCEEDING AND OVER THE LAST TEN YEARS, TO CONSIDER THE REGULATORY PROCEEDINGS THAT SHE HAS PARTICIPATED IN AND IDENTIFY THOSE THAT HAVE A COMPARABLE SCOPE.

Response

Below is a table provided by Pegasus-Global Holdings (PGH) in response to this undertaking. The table sets out regulatory proceedings within the last 10 years where PGH performed scopes of work that are comparable to the scope of work it performed in this proceeding.

It is noted that it is likely that some of the assignments which PGH has listed in Attachment 1 to Ex. L-4.3-15 SEC-040 also included scopes of work similar to the one performed for OPG in this proceeding. However, such assignments pre-date the last 10 years.

Chart 1

Project	Owner	Regulatory Body	Docket No.
Kemper County IGCC Power Plant*	Mississippi Power Company	Mississippi Public Service Commission	2013-UA-189
Edwardsport IGCC Power Plant*	Duke Energy Indiana	Indiana Utility Regulatory Commission	43114 IGCC-4S1
Levy County Nuclear Power Plant (Units 1 & 2)*	Progress Energy Florida	Florida Public Service Commission	100009-EI
Vogtle Electric Generating Plant (Units 3 & 4)^	Georgia Power Company	Georgia Public Service Commission	29849; 27800-U
Iatan Generating Station^	Kansas City Power & Light	Kansas Corporation Commission	09-KCPE-246-RTS; 10-KCPE-415-RTS
		Missouri Public Service Commission	ER-2009-0089; ER-2010-03551
*-Dr. Galloway filed testimony. ^-Dr. Galloway participated in the engagement, but did not file testimony.			

UNDERTAKING JT1.25

Undertaking

TO SPLIT OUT THOSE PROJECTS AGAINST THE FOUR CRITERIA THAT ARE ON PAGE 2 AS WELL AS THOSE ON PAGE 1 OF L-04.3-2 AMPCO 105.

Response

In response to Ex. L-04.3-2 AMPCO-105, OPG provided a list of criteria used to help establish whether a cost was to be included or excluded from the DRP cost baseline. The criteria are reproduced below:

1. Include: Direct cost of major bundle scope (vendor cost)
2. Include: Cost of resources (OPG cost) that directly support DRP project/program deliverables
3. Include: Incremental facilities and infrastructure required to enable DRP to complete its approved scope
4. Include: Pre-requisite activities if directly related to scope in the DRP execution window
5. Exclude Costs of OM&A activities that will continue through the DRP outage and would be performed even if the DRP project did not occur
6. Exclude: Incremental costs incurred by corporate/nuclear groups that do not directly support DRP project/program deliverables
7. Exclude: Costs of maintaining workforce capabilities, including training costs
8. Exclude: Facilities and programs funded by the Nuclear Liabilities Waste Provision

Additional criteria were established for emergent work:

a) If the work was required for continued operations of 1st life, then not DRP
b) Resulting scope from inspections funded by DRP are DRP scope
c) Resulting scope from inspections funded through operations OM&A are project portfolio scope

<u>Mapping of Excluded Costs to the Above Criteria:</u>

<u>Capital</u>

- Operations Support Building Refurbishment – Not #3 or #4, therefore, excluded from DRP
- Darlington Auxiliary Heating System – Not #3 or #4, therefore, excluded from DRP
- Emergency Service Water Pipe and Component Replacement – Not #3 or #4, therefore, excluded from DRP
- Primary Heat Transport Pump Motor Replacement/Overhaul – (a)
- Highway 401 and Holt Road Interchange – (a)

Exhibit L-04.3-1 Staff-071 part c) provides a detailed explanation for the above 5 projects

<u>OM&A</u>

- Unit Maintenance/Operations - #5
- Contracted Maintenance Programs - #5

- Engineering Systems Surveillance Activities - #5
- Operator Training Program - #7

UNDERTAKING JT1.26

Undertaking

TO ADVISE WHEN EACH ONE OF THE SHAFTS WERE LAST TESTED; ALSO, TO PROVIDE A SYNOPSIS OF THE STATE AND CONDITION AND TEST RESULTS.

Response

The Darlington station uses a 3-year cycle for planned unit outages. That is, each unit is shutdown for a planned outage every 3 years for inspections and maintenance. As mentioned in Ex. L-4.3-12 OAPPA-007, the Low Pressure (LP) turbine rotors are inspected on a planned 6-year interval and the High Pressure (HP) turbine rotors are inspected on a 9-year interval.

The HP rotors for Units 1, 2, 3, and 4 were last inspected in 2008, 2007, 2009, and 2013 respectively. The scope of the inspection included visual inspections, and magnetic particle inspection on all rotating blades, sealing strips, shaft and shaft gland areas. No significant findings were reported. This is summarized in Chart 1.

Chart 1
Listing of Most Recent HP Turbine Rotor Inspections at the Darlington Station

Unit	Latest HP Rotor Inspection	Scope of inspection	Findings
Unit 1	2008	Visual inspection, magnetic particle inspection on all rotating blades, sealing strips, shaft and shaft gland areas	No significant findings were reported
Unit 2	2007	Visual inspection, magnetic particle inspection on all rotating blades, sealing strips, shaft and shaft gland areas	No significant findings were reported
Unit 3	2009	Visual inspection, magnetic particle inspection on all rotating blades, sealing strips, shaft and shaft gland areas	No significant findings were reported
Unit 4	2013	Visual inspection, magnetic particle inspection on all rotating blades, sealing strips, shaft and shaft gland areas	No significant findings were reported

For the LP rotors, with three rotors per unit and a planned 6-year inspection interval for each LP rotor, in every unit outage at least one LP rotor is typically inspected, and in some outages, two LP rotors are inspected. As an example, in Unit 1, LP#1 and LP#3 were inspected in 2011 and LP#2 was inspected in 2014. These inspections included visual inspections, magnetic particle inspection on all rotor components, and ultrasonic inspection of the last 2 rows of blades. No significant findings were reported. Units 2, 3, and 4 had LP rotors inspected in, for example, 2010, 2015, 2016 with similar inspection scope and results. The full set of inspections since 2008 are summarized in Chart 2 below.

None of the previous LP rotor inspections have had significant findings that would change OPG's assessment that the rotors are likely to last until the end of Darlington's post-refurbishment life (nominally 30-35 years).

Chart 2
Listing of Most Recent LP Turbine Rotor Inspections at the Darlington Station

Unit	LP Rotor	Latest Rotor Inspection	Scope of inspection	Findings
Unit 1	LP1	2011	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP2	2014	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP3	2011	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
Unit 2	LP1	2010	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP2	2008	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP3	2010	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
Unit 3	LP1	2012	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP2	2015	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP3	2012	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
Unit 4	LP1	2013	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP2	2016	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported
	LP3	2013	Visual inspection, magnetic particle inspection on all rotor components, phased array UT of last 2 rows L-1 and L-0	No significant findings were reported