# Board Staff Interrogatory #116

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

## Interrogatory

**Reference:**
Ref: Exh F2-2-3 page 4 Chart 1

Please provide in table format the values for the variables noted in Chart 1 at the above reference.

## Response

The values for the variables noted in Chart 1 at Ex. F2-2-3, p. 4 are provided below:

| *($ Millions)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|
| Normal Operating Costs | 1,349 | 1,311 | 1,264 | 1,229 | 1,086 | 1,395 | 7,634 |
| Restoration of Normal Operating Costs | 0 | 15 | 32 | 56 | 147 | 0 | 250 |
| Enabling Costs | 15 | 26 | 55 | 107 | 104 | 0 | 307 |
| Total Costs | 1,364 | 1,351 | 1,351 | 1,392 | 1,338 | 1,395 | 8,191 |

OPG notes that there was an error in the data used to construct Chart 1 in Ex. F2-2-3, p. 4. A new chart will be filed as an evidence correction.

Table 2
Other Incremental Costs ($M)

| Line No. | Cost Item | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| | | | | | | |
| 1 | Fuel Expense | (5) | (7) | (9) | (21) | 117 |
| 2 | Inventory Obsolescence Charges | (10) | (10) | (10) | (10) | 12 |
| 3 | IESO Non-Energy Charges | 0 | 0 | 0 | 0 | 35 |
| 4 | Severance and Related Costs | 0 | 0 | 0 | 0 | (683) |
| 6 | Depreciation on Restoration Capital Expenditures | 0 | 0 | 0 | 8 | 50 |
| 7 | Cost of Capital for Working Capital Component of Rate Base | 2 | 5 | 8 | 16 | 19 |
| 8 | Property Tax | 0 | 0 | 0 | 0 | 6 |
| 9 | Income Tax | (0) | (0) | (0) | (11) | (32) |
| 10 | **Total** | (12) | (12) | (11) | (19) | (475) |

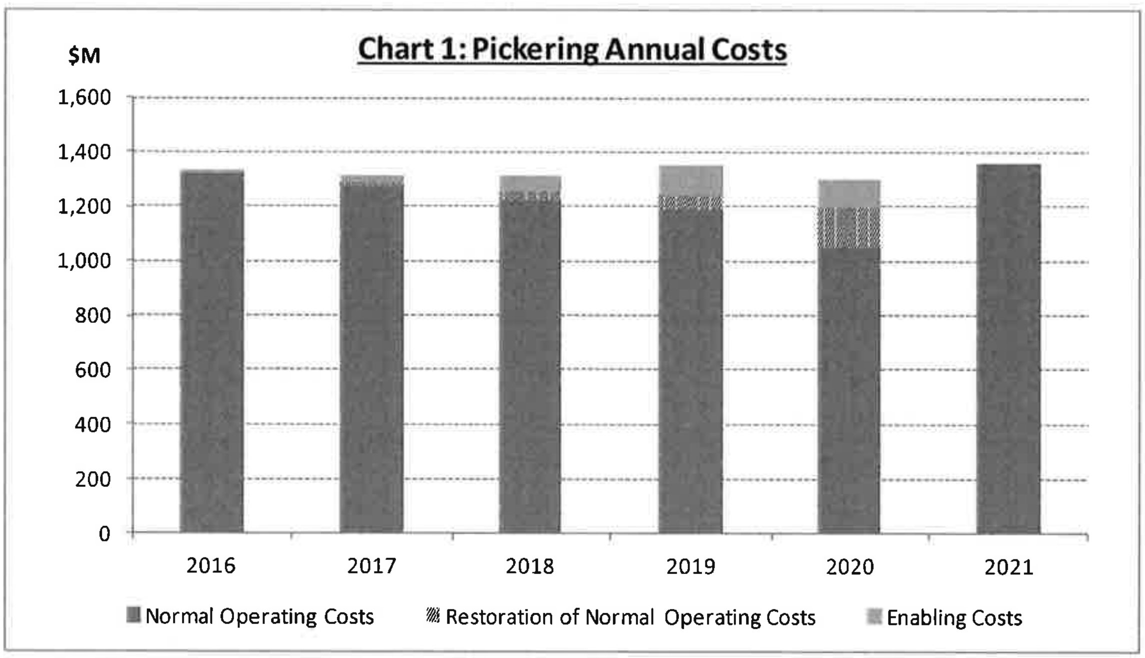
e) The basis for developing the cost estimates is explained in Ex. F2-2-3 Attachment 2 pp. 14 and 15 under the heading, "COSTS AND GENERATION ASSUMPTIONS" steps 1 through 8. The major categories of expenditures are provided in part (a) and (b) of this response. Processes to control costs and stay within approved plans are described in Ex. L-6.5-1-Staff-129.

f) The Normal Operating Costs shown in Table 1 above for the post 2020 period were prepared on a consistent basis with the information provided to the IESO, but are not the same. The post 2020 costs shown in Table 1 represent the costs underpinning OPG's application and are expressed on a fully allocated basis in escalated dollars whereas the information provided to the IESO was based on Ex. F2-2-3, Attachment 2 and is expressed in constant 2015$ and on an incremental basis as is explained in Ex. L-6.5-1 Staff-126.

g) The Business Case did take into consideration capital expenditures required during the test period and beyond 2020 as is shown in Ex. L-6.5-1 Staff-126 and explained in part c) of that response.

be undertaken over the test period. This work is comprised of enabling actions required to extend operations and secure the necessary CNSC approvals. In addition, funds necessary to support the plant's normal operating activities have been included over the 2016-2021 period. The cost of these activities would have previously been forecast to decline when the plant was scheduled to shutdown in 2020.

Chart 1 below shows the estimated costs to enable Extended Operations and operate Pickering in each year of the test period. While this exhibit discusses these costs, they are recovered primarily through the base, project and outage OM&A exhibits (Exhibits F2-2-1, F2-3-1 and F2-4-1, respectively) with the relatively smaller amount of capital expenditures for Pickering projects and minor fixed assets recovered through Ex. D2-1-2. Thus, there is no additional revenue requirement request associated with this exhibit.




### 3.3.1 Enabling Work and its Associated Cost

In advance of recommending Extended Operations, OPG completed an initial technical assessment of the Pickering units' continued ability to operate to the proposed shutdown

f) Please also comment on whether the Post 2020 operating costs noted in the referenced table are the same as that used by the IESO in its analysis.

g) Table E2 does not include any information on capital expenditures. Does the Business Case take into consideration the capital expenditures that are required in the test years and may be required in the 2021-2014 period?

## Response

a) & b) Exhibit F2-2-3 Attachment 2 Table E2 sets out OPG's estimate of operating costs (excluding fuel) to enable Extended Operations. In Table 1 below, the estimated costs in Table E2 have been updated to be consistent with forecasts underpinning OPG's evidence in this application. Table 1 includes a breakdown of the forecast costs to restore normal operations at Pickering over the period 2016 to 2020 as a result of extending plant life to 2022/2024, consistent with Chart 2 at Ex. F2-2-3 page 6:

Table 1
Pickering Extended Operations Costs per Application ($M)

| Line No. | Cost Item | 2016 | 2017 | 2018 | 2019 | 2020 | 2016-2020 Total | 2021 | 2022-2024 | 2016-2024 Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Enabling Costs** | | | | | | | | | |
| | **Nuclear Operations OM&A** | | | | | | | | | |
| 1 | **Base OM&A** | 11.0 | 1.0 | 0.0 | 0.0 | 0.0 | 12.0 | 0.0 | 0.0 | 12.0 |
| 2 | **Outage OM&A** | 0.0 | 22.1 | 37.3 | 88.7 | 85.5 | 233.6 | 0.0 | 0.0 | 233.6 |
| 3 | **Project OM&A** | 4.0 | 2.5 | 18.0 | 18.4 | 18.7 | 61.6 | 0.0 | 0.0 | 61.6 |
| 4 | **Total Enabling Costs** | 15.0 | 25.6 | 55.3 | 107.1 | 104.2 | 307.1 | 0.0 | 0.0 | 307.1 |
| | **Restoration / Normal Operating Costs** | | | | | | | | | |
| | **Nuclear Operations OM&A** | | | | | | | | | |
| 5 | **Base OM&A** | 0.0 | 7.9 | 13.5 | 28.4 | 61.6 | 111.4 | 765.5 | 1,818.9 | 2,695.8 |
| 6 | **Outage OM&A** | 0.0 | 0.0 | 0.0 | 0.0 | 47.2 | 47.2 | 244.2 | 376.8 | 668.2 |
| 7 | **Project OM&A** | 0.0 | 4.5 | 0.1 | 2.8 | 14.6 | 22.0 | 46.5 | 35.1 | 103.6 |
| 8 | **Sub-total Nuclear Operations OM&A** | 0.0 | 12.4 | 13.6 | 31.2 | 123.4 | 180.6 | 1,056.2 | 2,230.8 | 3,467.5 |
| 9 | **Project Capital (including Minor Fixed Assets)** | 0.0 | 0.0 | 15.5 | 17.6 | 13.1 | 46.2 | 23.1 | 6.7 | 75.9 |
| 10 | **Corporate Support** | 0.0 | 2.6 | 3.0 | 7.1 | 10.7 | 23.5 | 315.2 | 622.8 | 961.5 |
| 11 | **Total Restoration of Normal Operating Costs** | 0.0 | 15.0 | 32.1 | 55.9 | 147.2 | 250.3 | 1,394.5 | 2,860.2 | 4,504.9 |
| 12 | **Total Pickering Extended Operations Costs** | 15.0 | 40.6 | 87.4 | 163.0 | 251.4 | 557.4 | 1,394.5 | 2,860.2 | 4,812.1 |

As stated in Ex. F2-2-3, pp. 6 and 7, the restoration costs in this table are incremental as they are necessary to address the fact that with shutdown previously anticipated in 2020, ongoing operations and their costs were set to decline starting in 2017. With Extended Operations, OPG needs to restore on-

## Board Staff Interrogatory #117

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

### Interrogatory

**Reference:**
Ref: Exh F2-2-3

CNSC approval is required for Pickering Extended Operations.

a) It appears OPG is confident it will receive CNSC approval. Please describe the elements of OPG's proposal that is or will be before the CNSC that lead it to believe that it will likely receive CNSC approval for extended operations at Pickering.

b) What is OPG's plan in the event it does not receive CNSC approval?

c) In the event CNSC approval is delayed, what is the final date by which point OPG must determine if it is going to pursue Pickering operations beyond 2020?

d) How much of the proposed $307M budget to enable PEO will have been spent by this point?

### Response

a) OPG will provide a complete and detailed licence application that meets all requirements for a licence to operate a nuclear power plant. This application will include, for example, the technical basis for operation to 2024. This technical basis is founded on numerous detailed inspections of the physical condition of the Pickering station, demonstrating it is and will remain fit for service through the requested operating life.

OPG's licence application will also be based on CNSC accepted methodology to predict the future aging of the station and on commitments to continually inspect, analyze, and report the physical condition of the plant. At all times, OPG expects to be able to demonstrate to the CNSC that sufficient safe operating margin is present.

The licence application will also provide updates on Pickering's performance over the past few years, including the fact that OPG's safety record remains exemplary.

The application will address our improvement plans for the extended operations period, which will be based on a detailed Periodic Safety Review (PSR). The PSR, which complies with CNSC regulatory requirements, assesses plant component condition and compares our programs to modern codes and standards. Any gaps must be addressed, and improvement plans developed and accepted by the CNSC as part of the licensing process.

OPG's compliance with the CNSC's regulatory framework requirements and licensing process, and our demonstrated excellent plant performance in recent years, provide confidence that the Commission will approve operation of the Pickering station past 2020.

b) OPG is confident that the CNSC will provide approval to continue to operate the Pickering station past 2020, but realizes that there could be regulatory conditions attached to that approval. OPG would plan to meet any regulatory requirements set by the Commission except in the unlikely event that such conditions are unreasonably onerous in terms of cost or practicality. If conditions imposed were to cause OPG to revise its plans to operate Pickering, it would consult with its Shareholder regarding any potential changes to the planned end of commercial operation date.

It is also possible that the Commission might choose to issue a shorter licence than 10 years. In that event, OPG would plan to apply for a new licence prior to the end of the next licence term.

c) The CNSC Commission will issue a licence by August 31, 2018 (i.e., it won't be delayed). See answer to part b) above. There is no "final date" by which OPG must determine pursuit of operation beyond 2020.

d) See response to c) above. If a decision is ultimately made to not pursue extended operations, a re-evaluation of the future work program and going forward costs would have to be completed at that time based on the requirements in the CNSC decision that led OPG not to pursue operation to 2022/2024 as currently planned.

# Board Staff Interrogatory #121

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

## Interrogatory

**Reference:**
Ref: Exh D2-1-3 Table 5b
In Table 5b at Exh D2-1-3, OPG has provided a listing of 19 projects that are to be funded through the test year Unallocated Capital.

a) It is not clear to OEB staff which of these projects is specifically related to ensuring the operation of Pickering beyond 2020. Please expand Table 5b by adding additional columns to include the following information: Identify the project driver for each project in the table as "PEO" or "PCO" or "other"; identify the planned in-service date for each project; total estimated capital expenditure for each project and in- service date.

b) Please confirm that the projects listed in Table 5a, relate exclusively to the DRP and are not intended to enable Pickering Extended Operations. If that is not true, please identify the projects in Table 5a that are intended to enable Pickering Extended Operations.

## Response

a) None of the projects listed in Ex. D2-1-3 Table 5b are required to ensure operation of the Pickering station beyond 2020. The projects listed in Ex. D2-1-3 Table 5b have been identified to maintain safe and reliable operations to 2020 and are proposed projects to be started in the years listed. At this time, there has not been sufficient engineering, planning or estimating completed to provide estimates and in-service dates as requested.

   Any potential projects that may be required to ensure operations beyond 2020 will be identified following the completion of the Periodic Safety Review and other technical assessments that are currently in progress.

b) OPG does not confirm that the projects listed in Ex. D2-1-3 Table 5a relate exclusively to the Darlington Refurbishment Program. Rather, the projects listed in Ex. D2-1-3 Table 5a are modifications planned for the Darlington station. None of the projects in Ex. D2-1-3 Table 5a are intended to enable Pickering Extended Operations.

# Board Staff Interrogatory #126

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

**Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.**

## Interrogatory

**Reference:**
Ref: Exh F2-2-3 Attachment 1 page 3

At the above reference the IESO states in part: "Potential for cost savings although these depend on the outlook for Pickering production and operating costs (which have a lower degree of uncertainty and can be controlled to some degree)...."

a) Please provide the production and operating costs assumptions for Pickering for the period 2021-2024 that were used in the March 2015 study and the October 2015 update. Please provide this information in table format and by year. Please provide OPG's views on the appropriateness of the two assumptions including the rate of growth.

b) For comparison purposes please provide the production and operating costs for Pickering, for the period 2016-2020. Please provide this information in the same format and on the same basis as in part (a).

c) Does the IESO study also take into account capital expenditures that will be required during the 2021-2024 period? What were the assumptions in the study?

## Response

a) & b) The production and cost data provided to the IESO that was used in the March 2015 and October 2015 studies are provided below in Chart 1 and Chart 2:

Chart 1

**PICKERING EXTENDED OPERATIONS** Assessment Data (Scenario ~ 73 TWh)
**(March 2015)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Incremental Production (TWh) | **0.0** | **0.0** | **-0.5** | **-0.2** | **-2.6** | **22.1** | **22.6** | **15.1** | **16.5** | **72.9** |

**Incremental Operating Costs ($2015M)**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Total OM&A | 0 | 0 | 48 | 35 | 133 | 927 | 901 | 643 | 567 | **3,254** |
| Total Capital | 0 | 0 | 19 | 19 | 14 | 24 | 11 | 7 | 7 | **102** |
| **Total Operating Costs** | **0** | **0** | **67** | **55** | **147** | **951** | **911** | **650** | **574** | **3,356** |
| Fuel | 0 | 0 | -3 | -1 | -14 | 119 | 122 | 85 | 93 | **401** |

Chart 2

**PICKERING EXTENDED OPERATIONS** Assessment Data (BCS Option 1 ~ 65 TWh)
**(October 2015)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Incremental Production (TWh) | **0.0** | **-0.9** | **-1.2** | **-1.8** | **-3.4** | **19.6** | **21.2** | **14.6** | **16.5** | **64.5** |

**Incremental Operating Costs ($2015M)**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Total OM&A | 7 | 35 | 64 | 129 | 207 | 965 | 891 | 623 | 487 | **3,408** |
| Total Capital | 0 | 0 | 15 | 16 | 11 | 22 | 10 | 7 | 7 | **89** |
| **Total Operating Costs** | **7** | **35** | **79** | **145** | **218** | **987** | **902** | **631** | **494** | **3,497** |
| Fuel | 0 | -5 | -6 | -9 | -18 | 105 | 113 | 79 | 89 | **347** |

**PICKERING EXTENDED OPERATIONS** Assessment Data (BCS Option 2 ~ 62 TWh)
**(October 2015)**

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Incremental Production (TWh) | **0.0** | **-0.9** | **-1.2** | **-1.6** | **-3.8** | **18.8** | **20.2** | **13.8** | **16.1** | **61.5** |

**Incremental Operating Costs ($2015M)**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Total OM&A | 7 | 35 | 64 | 129 | 207 | 965 | 891 | 623 | 487 | **3,408** |
| Total Capital | 0 | 0 | 15 | 16 | 11 | 22 | 10 | 7 | 7 | **89** |
| **Total Operating Costs** | **7** | **35** | **79** | **145** | **218** | **987** | **902** | **631** | **494** | **3,497** |
| Fuel | 0 | -5 | -6 | -8 | -19 | 101 | 108 | 74 | 87 | **331** |

The March 2015 data was provided to the IESO in December 2014 and was expressed in 2014$. The March table referenced above was converted to 2015$ consistent with the October data for comparison purposes.

Total OM&A includes base, outage, projects, the station's portion of incremental allocated nuclear and corporate support costs and estimated costs to enable extended operations.

Total Capital costs include Minor Fixed Asset expenditures.

OPG believes the production data reflecting approximately 62 TWh of incremental production estimated in October 2015 is achievable and most accurately reflects the planned outage activities required to extend Pickering operations. The cost data also estimated in October 2015 accurately reflects the forecast incremental costs required to execute the work program to extend Pickering operations as described in Ex. F2-2-3 Attachment 2.

c) Yes, the study includes capital expenditures. These amounts are reflected in the Total Capital rows in the Charts in parts a) and b) above.

# Board Staff Interrogatory #128

**Issue Number: 6.5**
**Issue:** Are the test period expenditures related to extended operations for Pickering appropriate?

**Below are interrogatories on the IESO's analysis (Exh F2-2-3 Attachment 1) of Pickering Extended Operations. In order to provide complete responses to all OEB staff interrogatories please consult the IESO as necessary.**

## Interrogatory

**Reference:**
Ref: Exh F2-2-3 Attachment 1 page 15

a) What was the reason for reducing the production forecast from 73 TWh (in March 2015 study) to 62 TWh and 65 TWh (in October 2015 update)?

b) What is the level of production below the assumed 62 TWh where the net benefits of extended operations cease?

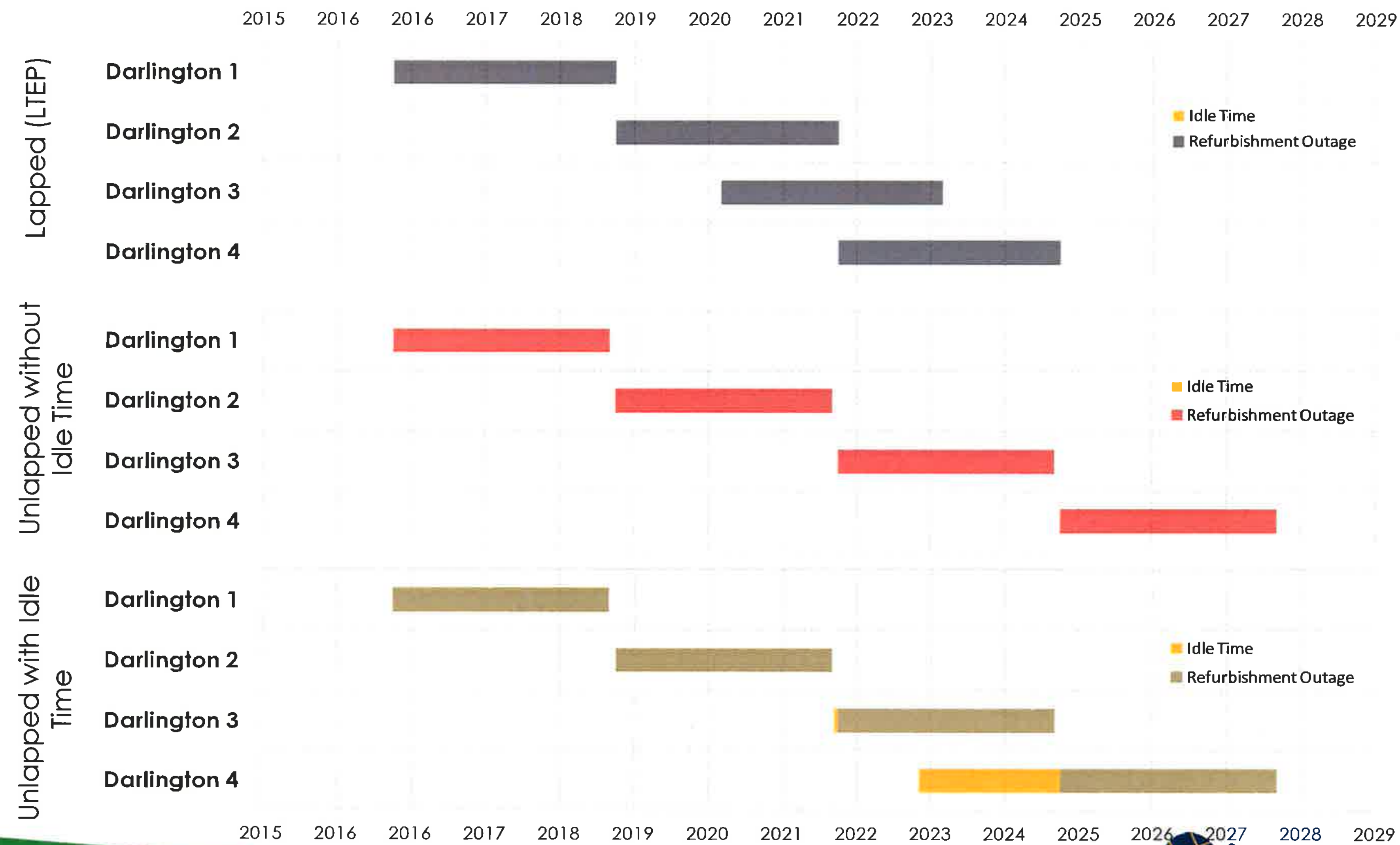
## Response

a) The 73 TWh production forecast was developed in December 2014 based on a preliminary understanding of the scope of work required under various alternatives being developed for extended operations. During 2015, OPG focused on the preferred extended operations alternative and developed a more rigorous production forecast. In particular, planned outage durations were refined based on a detailed understanding of the scope of work in each outage under the preferred alternative. This is the primary reason why the production forecast was reduced for the October 2015 update.

b) The following response has been prepared by the IESO:

The IESO estimates that the net benefit of Pickering Life Extension ceases at a Pickering incremental production level (i.e. the difference in energy production with Pickering to 2022/2024 as compared to Pickering to 2020) of 56 TWh.

Pickering extension options were assessed against three Darlington refurbishment sequences. One sequence features some overlap among Darlington refurbishments. Two sequences feature no overlap - in sequences without overlap, one relies on idle time at Darlington units 3 and 4 to attain the required service life.




ieso
Independent Electricity System Operator

# Board Staff Interrogatory #28

**Issue Number: 4.2**
**Issue:** Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

## Interrogatory

**Reference:**
Ref: Exh D2-1-3, Attachment 1, Tab 20

The BCS for the Darlington Powerhouse Water Air Cooler Units Replacements project states that a full release BCS is expected to be approved with a target date of April 2016, following completion of detailed engineering for all units and procurement of all materials under the current BCS. The BCS also states that OPG Project Management and Engineering costs will be significantly higher than previously estimated.

a) Please provide an update on the project schedule and cost including whether the full release BCS has been approved as planned.

b) Please explain the underlying basis for the higher OPG Project Management and Engineering costs relative to the EPC contractor's work scope and responsibilities.

## Response

a) A partial execution BCS was approved in September 2016 (see Attachment 1 which contains confidential information as marked). The updated total project cost is $26.6M. The increase is mainly due to equipment, engineering and construction cost increases. The cost of Air Cooling Units (ACUs), based on costs obtained from competitive bids, is higher than the original estimate. Engineering and construction costs are higher, due to the addition of mist eliminators and required relocation of some ACUs and interfering services. The target in-service date has changed from December 2019 to January 2023, as a result of the delay encountered in issuing the equipment purchase order, and delays in completing detailed engineering. The project schedule was re-evaluated and associated dates have been reflected in the latest BCS.

b) Based on experience from similar projects, OPG project oversight and cost has increased to support the resolution of construction issues. In the latest BCS, OPG Project Management and Engineering costs were reviewed and adjusted to reflect actual experience to-date on this project.

# Board Staff Interrogatory #41

**Issue Number: 4.2**
**Issue:** Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

## Interrogatory

**Reference:**
Ref: Exh D2-1-3, Attachment 1, Tab 33

This BCS relates to the Darlington Primary Heat Transport (PHT) Pump Motor Replacement/Overhaul project. The BCS states that the alternative of buying new PHT pump motors is not recommended based on higher cost and duration. The BCS also states that this alternative would be re-evaluated if overhaul motor cost reaches $5M per motor. The BCS further states that operational experience shows that PHT pump motors manufactured by the same Original Equipment Manufacturer have similar problems at U.S stations and that another Canadian CANDU operator is also refurbishing their PHT pump motors.

a) Based on the project schedule information in the BCS, overhaul costs for one or, possibly two PHT pump motors should be available in the meantime.
Please confirm whether this information is available and, if so, does OPG still plan to proceed with the preferred alternative of overhauling all PHT pump motors?

b) Has OPG conducted any benchmarking cost comparisons with other nuclear utilities that have undertaken similar PHT pump motor refurbishment and replacement projects? If yes, how do OPG project costs for PHT pump motor refurbishment and replacement compare to these external projects?

## Response

a) The actual cost for a fully refurbished PHT pump motor is not available at this time.
In order to accelerate the replacement program as a result of losses sustained due to a PHT Pump Motor failure in 2015, OPG decided in May 2016 (See Attachment 1 which has confidential content as marked) to purchase four new motors and reduce the number of motors to be refurbished accordingly.

b) OPG has reviewed the motor replacement strategies with other utilities. OPG has also engaged industry motor experts to assist with the evaluation and review of both refurbished and new PHT motors.

## AMPCO Interrogatory #29

**Issue Number: 4.2**
**Issue:** Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

### Interrogatory

**Reference:**
Ref 1: D2-1-1 Page 1

a) For the years 2013 to 2021, please provide a breakdown of the Nuclear Operations Capital Project Portfolio budget allocated to regulatory, system or unit reliability, system obsolescence or optimizing station generation.

### Response

The breakdown as requested is provided in Chart 1 below.

The regulatory category has been interpreted to include projects that replace equipment required to support regulatory requirements as well as projects required by regulatory actions or changed regulation. As such, this total will be different than the total shown in D2-1-2 Table 3, which follows the OPG definition of regulatory projects (i.e., projects required by regulatory actions or regulation change).

The Other category was included for projects, such as facility construction, that do not meet any of the other categories. The Unallocated portion of the Portfolio is not included in the breakdown.

**Chart 1**

| Line No. | Category ($M) | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Budget | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 1 | Regulatory | 55.4 | 107.3 | 85.4 | 96.1 | 54.2 | 32.5 | 15.5 | 15.4 | 8.4 |
| 2 | Unit/System Reliability | 59.8 | 69.6 | 95.5 | 132.9 | 79.4 | 55.0 | 42.9 | 6.1 | 3.6 |
| 3 | System Obsolescence | 44.3 | 52.1 | 49.1 | 73.3 | 65.1 | 53.0 | 26.3 | 16.0 | 18.2 |
| 4 | Generation Optimization | 2.7 | 5.7 | 9.6 | 8.0 | 3.5 | 1.1 | 2.3 | 0.0 | 0.0 |
| 5 | Other | 28.6 | 35.1 | 52.9 | 6.3 | 1.9 | 1.9 | 1.6 | 0.0 | 0.0 |
| 6 | Unallocated | 0.0 | 0.0 | 0.0 | 5.5 | 48.8 | 94.6 | 159.4 | 221.6 | 149.8 |
| 7 | **Total** | **190.9** | **269.8** | **292.5** | **322.0** | **253.0** | **238.0** | **248.0** | **259.0** | **180.0** |

Numbers may not add due to rounding.

Witness Panel: Nuclear Operations and Projects

## SEC Interrogatory #46

**Issue Number: 4.4**

**Issue:** Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

### Interrogatory

**Reference:**
[D2/1/2]
Please provide a table showing for each capital nuclear capital project (tier 1, 2 and 3) that will go in-service between 2014 and 2016, its forecasted cost and its actual cost. Please provide an explanation for all variances +/- 5% and why it is prudent. Please provide a copy of all Project Over-Variance Approval documents for those projects not already included in the pre-filed evidence.

### Response

Following is a table showing all Tier 1, 2 and 3 projects that have or are scheduled to go in-service between 2014 and 2016 as of October 15, 2016.

There are no projects with actual or forecasted costs that exceed approved costs (i.e. total project cost including contingency in the most recent BCS). Projects obtain approval for increased costs through over-variance approvals or superseding business cases before their approved amount is exceeded. No explanations are provided where the in-service amount is less than the approved cost of the project. An outcome where the final in-service amount will be less than the approved amount is not unexpected since the approved amount includes contingency, which may not be fully used in some projects.

| Projects | OEB Tier | Actual or Forecast In-Service Date | Actual or Forecast In-Service (M$) | Approved Cost (M$) | Variance (M$) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| 25619 - DN OSB Refurbishment | 1 | Oct-15 | 60.6 | 62.7 | (2.1) |
| 33955 - Shutdown System Computer Aging Management | 1 | Nov-16 | 20.4 | 20.4 | 0.0 |
| 34000 - DN Auxiliary Heating System | 1 | Oct-17 | 98.7 | 107.1 | (8.4) |
| 41023 - Unit 1 & 4 Fuel Channel East Pressure Tube Shift Tooling (Capital) | 1 | Mar-16 | 27.8 | 29.7 | (1.9) |
| 73706 - DN Holt Road Interchange Upgrade | 1 | Aug-16 | 24.6 | 31.0 | (4.0) |

| **Projects** | **OEB Tier** | **Actual or Forecast In-Service Date** | **Actual or Forecast In-Service (M$)** | **Approved Cost (M$)** | **Variance (M$)** |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| 31306 - DN Passive Auto-Catalytic Recombiners | 2 | Jun-16 | 5.1 | 5.8 | (0.7) |
| 33623 - DN Installation of partial discharge monitors | 2 | Feb-14 | 5.6 | 7.1 | (1.5) |
| 36002 - DN MOT Capital Spares | 2 | Sep-16 | 8.1 | 8.3 | (0.2) |
| 40680 - PB Main Generator AVR and Protective Relay Upgrade | 2 | Jul-15 | 18.7 | 18.8 | (0.1) |
| 46605 - PA Passive Auto-Catalytic Recombiners | 2 | May-14 | 12.1 | 14.4 | (2.3) |
| 49116 - PB SG/EPG Fire Detection Upgrade and CO2 Suppression Removal | 2 | Jul-16 | 6.9 | 10.7 | (3.8) |
| 49126 - PB Powerhouse Office Facilities (Capital) | 2 | Dec-14 | 4.2 | 6.7 | (2.5) |
| 49132 - PB RBSW Dechlorination & MISA Cleanup | 2 | Dec-16 | 14.1 | 14.1 | (0.0) |
| 49134 - PB Replacement of Containment Box-up Monitors | 2 | Jul-15 | 6.9 | 8.8 | (1.9) |
| 49140 - PB Screenhouse Trash Bar Screen Replacement | 2 | Jul-15 | 6.8 | 7.7 | (0.9) |
| 49146 - PN Fire Code Compliance for Relocatable Structures in Un-Zoned Area for Pickering Station | 2 | Jul-16 | 17.1 | 18.8 | (1.7) |
| 49247 - Unit 1 & 4 Fuel Channel East Pressure Tube Shift Tooling (CMFA) | 2 | Mar-16 | 8.7 | 8.9 | (0.2) |
| 49267 - PN Standby Boiler Capacity Improvement | 2 | Nov-15 | 5.1 | 6.4 | (1.3) |
| 49284 - PN Administration Building Rehab | 2 | Dec-14 | 16.4 | 19.4 | (3.0) |
| 49296 - PA Class II Emergency Lighting | 2 | Aug-15 | 4.0 | 6.1 | (2.1) |
| 66255 - OPGN Pressure Tube to Calandria Tube Gap | 2 | Aug-15 | 16.8 | 17.5 | (0.7) |
| 66533 - Multiple Simultaneous Inspections for Feeders | 2 | Sep-14 | 0.4 | 0.5 | (0.0) |
| 73397 - DN ESW Pipe and Component Replacement | 2 | Jan-16 | 5.2 | 6.7 | (1.5) |
| 80027 - SES Station Personnel Emergency Accounting | 2 | Dec-16 | 0.2 | 3.3 | (3.2) |
| 25918 - Security Project A | 2 | Dec-16 | 9.9 | 9.9 | 0.0 |
| 31406 - DN SG Battery Rectifier upgrade | 3 | Mar-14 | 3.8 | 4.0 | (0.2) |

| Projects | OEB Tier | Actual or Forecast In-Service Date | Actual or Forecast In-Service (M$) | Approved Cost (M$) | Variance (M$) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| (Capital) | | | | | |
| 31410 - DN TRF CRS Hydrogen Compressors Condition Monitoring System | 3 | May-16 | 6.6 | 6.6 | (0.0) |
| 31437 - DN F/H Service Area Bridge Mtce Platform | 3 | Dec-14 | 0.6 | 0.6 | (0.0) |
| 31530 - DN MOT/LIST/SST/10MVA Spare Transformer Storage Facility | 3 | Sep-16 | 5.1 | 5.6 | (0.5) |
| 31538 - DN RIH Instrumentation Upgrade | 3 | Dec-16 | 1.4 | 1.7 | (0.3) |
| 33214 - DN Building Heating Condensate Return Header Pipe Movement | 3 | Jan-16 | 2.8 | 2.8 | 0.0 |
| 33218 - DN Bleed Condenser Isolating Valve - Unit 1 | 3 | Jul-14 | 1.2 | 1.5 | (0.3) |
| 33220 - DN End Shield Cooling Button-up Valve Access Platform | 3 | Dec-14 | 0.8 | 0.8 | (0.0) |
| 33222 - DN FH IFB ESW Top-up Valve Access Platform | 3 | Apr-15 | 0.7 | 0.7 | (0.0) |
| 33904 - Plant Information System Addt'n in the MCR | 3 | Apr-14 | 4.6 | 4.8 | (0.2) |
| 36005 - DN Class IV 4kV 10MVA Transformer Capital Spare | 3 | Oct-16 | 0.5 | 0.5 | 0.0 |
| 36007 - DN UST Capital Spare | 3 | Oct-16 | 2.7 | 3.0 | (0.3) |
| 38946 - DN Domestic Waterline Replacement | 3 | Dec-15 | 3.4 | 3.9 | (0.5) |
| 40658 - PB Boiler Level Control Obsolescence | 3 | Feb-15 | 1.9 | 2.9 | (1.1) |
| 40692 - PB Turbine Supervisory Equipment (TSE) Obsolescence (Capital) | 3 | Dec-16 | 3.9 | 5.0 | (1.1) |
| 40708 - PB Bleed Condenser Bundle Replacement | 3 | Jan-16 | 3.9 | 4.4 | (0.5) |
| 40975 - PN N293-07 Fire Code Compliance Modifications | 3 | May-15 | 4.3 | 4.3 | 0.0 |
| 40978 - PN Fueling Machine Vault Camera Replacement | 3 | Dec-16 | 4.0 | 4.2 | (0.2) |
| 40982 - PA Enhancement of Pickering A Chlorination System (Capital) | 3 | Sep-15 | 3.1 | 3.4 | (0.3) |
| 40987 - PA Replacement of AIFB Supertool | 3 | Dec-16 | 3.1 | 3.4 | (0.3) |
| 40992 - PN Replacement of Auto Transfer Switch ATS1 & ATS2 | 3 | Aug-14 | 0.4 | 0.4 | (0.0) |
| 40993 - PA Bulk CO2 Tank Replacement | 3 | Aug-14 | 1.2 | 1.5 | (0.3) |
| 40994 - PA Fire Water Chlorination Skid | 3 | Sep-16 | 1.6 | 1.7 | (0.2) |

| Projects | OEB Tier | Actual or Forecast In-Service Date | Actual or Forecast In-Service (M$) | Approved Cost (M$) | Variance (M$) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| 40998 - PA Generator Field Breaker Replacement | 3 | May-14 | 0.8 | 1.0 | (0.2) |
| 40999 - PA Generator Turbine Temperature Monitor Replacement | 3 | Apr-15 | 0.3 | 0.4 | (0.1) |
| 41005 - PA Reheat Drain Pumps Reliability Improvement | 3 | Dec-16 | 2.3 | 2.3 | 0.0 |
| 41006 - PN Comfo Washer Replacement | 3 | Nov-16 | 0.5 | 0.6 | (0.1) |
| 41008 - PN South Decontamination Shop Facility Upgrade | 3 | Feb-14 | 0.2 | 0.4 | (0.2) |
| 41009 - PA SRV Enclosure Ventilation Improvement | 3 | May-15 | 1.3 | 1.5 | (0.1) |
| 41011 - PN Upper Chamber Vacuum Pumps Replacement | 3 | Mar-14 | 0.3 | 1.0 | (0.7) |
| 41012 - PA 230 kV Disconnect Switches Replacement (DS138/DS142/DS154) | 3 | Apr-14 | 1.0 | 1.9 | (0.9) |
| 41033 - PN Whole Body Monitor Seismic Qualification | 3 | Feb-14 | 0.4 | 1.2 | (0.9) |
| 41034 - PA Fire Code Compliance (FSA Followup) | 3 | Jun-15 | 2.8 | 3.0 | (0.2) |
| 41040 - PN Permanent Power Supplies For Ontario Electrical Safety Code Compliance | 3 | Apr-14 | 0.8 | 0.9 | (0.1) |
| 41047 - PA Critical Pump and Motor Spares | 3 | Dec-15 | 0.5 | 2.9 | (2.4) |
| 49124 - PB Permanent Data Logger for Screenhouse | 3 | Sep-15 | 3.3 | 3.5 | (0.2) |
| 49142 - Pickering Site Engineering Services Bldg - 1 (ESB1) HVAC System Upgraders | 3 | Sep-14 | 4.2 | 4.4 | (0.2) |
| 49143 - PB Purchase of CEP Motor Capital Spares | 3 | Mar-16 | 0.3 | 0.3 | (0.0) |
| 49144 - PB Purchase of HPSW Motor Capital Spares | 3 | Mar-16 | 0.2 | 0.2 | 0.0 |
| 49163 - PA Fire Code Compliance for Relocatable Structures in Powerhouse | 3 | Dec-16 | 2.0 | 4.8 | (2.8) |
| 49289 - Pickering A - AVR Replacement for Standby Generators | 3 | Jul-16 | 4.8 | 4.8 | 0.0 |
| 49302 - PB Fire Code Compliance for Relocatable Structures in Powerhouse | 3 | Jan-16 | 2.9 | 4.6 | (1.6) |
| 62552 - Inspection Qualification | 3 | Dec-16 | 3.4 | 3.4 | (0.0) |
| 66599 - IMS Steam Generator Inspection | 3 | Dec-14 | 1.5 | 2.5 | (0.9) |

| Projects | OEB Tier | Actual or Forecast In-Service Date | Actual or Forecast In-Service (M$) | Approved Cost (M$) | Variance (M$) |
|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) |
| Improvements | | | | | |
| 80020 - DN TRF Cold Box Vacuum System Obsolescence | 3 | May-16 | 3.7 | 4.9 | (1.3) |
| 80119 - PA Switchyard Air Blast Circuit Breaker Replacement | 3 | Apr-14 | 3.5 | 3.5 | 0.0 |
| 80149 - DN Sewage Lift Station Replacement | 3 | Feb-16 | 1.2 | 4.8 | (3.5) |

Attached are the Tier 1 Over-Variance Approval or Superseding Business Cases #33955 (Attachment 1) and #34000 (Attachment 2) that have received approval and have not been included in the pre-filed evidence or in response to other interrogatories. Attachment 2 includes confidential content as marked.

## Board Staff Interrogatory #82

**Issue Number: 5.1**
**Issue:** Is the proposed nuclear production forecast appropriate?

### Interrogatory

**Reference:**
Ref: E2-1-1, page 3
OPG states that it will undertake two "warranty" outages on Darlington unit 2 in 2020 and 2021. OPG states that the "need for these post-refurbishment mini-outages is based on operating experience at other nuclear facilities that underwent major refurbishment."

a) Does OPG have any documentation or reports to support the need for these "mini-outages"? If so, can OPG file these reports with the OEB? If not, please provide further details regarding the experiences supporting the need for these outages.

b) OPG states that the need for these outages is based on experience at other nuclear facilities. Please identify which other nuclear facilities OPG is referring to specifically. Are these CANDU facilities or other technologies?

c) OPG's first warranty outage on Darlington Unit 2 is scheduled to last for 55 days in 2020.

    i. On what basis was the 55 day duration chosen? Does OPG have examples or experience from previous refurbishment processes to support this specific length of outage?
    ii. What types of equipment repair does OPG anticipate will be required during this outage? Is there documentation to support these expectations?

d) Referring to these outages as "warranty" outages implies that vendors may assume some liability for costs associated with these outages.
    i. Are vendors liable for any costs associated with these outages? If so, is this liability specifically addressed in the vendor contracts?
    ii. Can OPG provide documentation to define these liabilities? If vendors are liable for costs, what are the limits of their liability?
    iii. Does this liability include compensation for lost production?

e) OPG's submission allows for a second warranty outage of 33 days duration for Unit 2 in 2021. OPG states that "the shorter duration is due to an expectation that the majority of scope required to be addressed post-refurbishment will be completed during the first post refurbishment mini-outage in 2020."
    i. How certain is OPG that this second outage will be required? What experience underpins this allowance for a second outage?
    ii. Does OPG have any concerns that scheduling a second warranty outage will

affect vendors' performance in addressing corrective actions during the first warranty outage?

iii. Do vendors have performance incentives that could lessen the need for, or, the length of, the second warranty outage?

**Response**

a) OPG does not have any documentation or reports to support the need for the post commissioning mini-outages. The need for these outages is based on examining operating experience at other refurbished CANDU plants – Point Lepreau, Bruce A, Pickering A, and Wolsong – which shows that a refurbished plant can expect to encounter a number of emergent equipment related issues immediately following post refurbishment that can result in forced outages (see Ex. L-5.1-1 Staff-81) and/or the need for small scope mini outages in the period immediately following commissioning. In particular, Point Lepreau was required to schedule a number of outages post commissioning to fix emergent issues that arose.

b) As identified above, the nuclear facilities that OPG examined to determine the needs for the post commissioning mini-outages were Point Lepreau, Bruce A, Pickering A and Wolsong. All are CANDU plants.

c)

i. The 55 day duration was chosen based on an assessment of the required length of outage to fix a major equipment issue. OPG's determination was based on examples from the Point Lepreau refurbishment and Pickering A return to service where post commissioning issues with governor valves, high leakage to collection, liquid zone control system and moderator system valves were encountered.

ii. In addition to the examples provided above, a failure of newly installed components such as pump seals might result in high leakage and require a shutdown to fix. As well, there is a risk that laid up systems may experience emergent degradation requiring an outage to repair. For example, feedwater or turbine-generator components required for full power operation may have degraded during the multi-year refurbishment layup and require fixing in a post commissioning mini-outage.

d)

i. OPG will not know until the outage if there is any work subject to the contractual warranty provisions required. If there is, OPG's contracts generally provide that the warranty work is carried out at the contractors' costs.

ii. The contracts vary with respect to warranty obligations and limitations of liability. Please see the contract summaries at Ex. D2-2-3, Attachments 1 to 5 and the full contracts at Ex. D2-2-3, Attachments 6 to 10 for details on the warranty clauses and the limitation of liability clauses in the contracts.

iii. OPG's contracts do not generally provide that a contractor will pay for lost production. Please see the warranty clauses in the contract summaries and the contracts filed at Ex. D2-2-3, Attachments 1 to 10 for more detail.

e)

i. OPG is reasonably certain that this outage will be required. Although it is impossible to specifically identify the exact need, again based on operating experience at other CANDU plants as identified above, equipment issues resultant for new and laid up equipment not identified in the first 6 months following refurbishment will require a second post commissioning mini-outage to fix.

ii. Warranty issues identified in the outage should be corrected as quickly as possible. OPG is not concerned that scheduling a second warranty outage will affect a contractor's performance as it is in the contractor's interest to fulfill their warranty obligations as soon as possible. Late corrections will increase a contractor's cost for fulfilling their warranty obligations.

iii. Other than the cost minimization incentive indicated in part ii, there are no performance incentives associated with a potential second warranty outage.

## Board Staff Interrogatory #83

**Issue Number: 5.1**
**Issue:** Is the proposed nuclear production forecast appropriate?

### Interrogatory

**Reference:**
Ref: E2-1-1, page 4
OPG has stated that it expects Pickering's annual FLR to stabilize at 5% from 2016 through 2021. This was attributed to equipment reliability and fuel handling improvement initiatives.

a) Generally, what factors are considered in the assessment when forecasting the FLR and how is it calculated?

b) What are the specific factors, assumptions and experiences that have led to the expectation of an FLR of 5% over the 2016-2020 period for the Pickering units.

### Response

a) Forced Loss Rate ("FLR") forecasts are developed by assessing a number of interlinked factors. As discussed at Ex. E2-1-1, pp. 8-9, these include:

- An assessment of the FLR historical trending performance
- An assessment of Equipment Reliability Index and Plant System Health, looking at historical trends and expected future equipment condition, including fuel handling equipment reliability.
- A review of maintenance backlogs, both historical trends and expected future performance
- An assessment of human performance, both historical trends and expected future performance.
- An assessment of capital and OM&A project investments, and the timing of specific project availability for service.
- Any known improvements or plant material condition issues.

The determination of FLR is described at Ex. E2-1-1 Attachment 1, p. 1.

b) The forecast of a 5% FLR for Pickering over the 2016 to 2020 period is based on the following assumptions:

- Pickering has continued to make investments in programs to improve equipment reliability and plant system health, including a multi-year trend of reducing backlogs. This included identifying and executing key reliability work orders over a multi-year period. Corrective maintenance backlogs are at a multi-year low for the station.

- Pickering has made improvements and intends to continue to improve in the area of human performance.

- OPG continues to make capital investments in Pickering, with a focus specifically on systems that have previously been associated with high production losses as well as components at end of life where there is increased risk of unforeseen failures. These include fuel handling equipment reliability improvements and replacements of motors and seals associated with the primary heat transport and shutdown cooling systems. Capital investments are assessed from a value for money perspective based on their cost versus their potential to reduce the risk of forced outages.

- Chart 4 from Ex. E2-1-1, p. 9 that is reproduced below shows Pickering's FLR averaged 8.5% over the period 2010 to 2015 due in particular to excellent performance in 2015. A forecast of 5.0% for Pickering FLR is consistent with Pickering's improving FLR trend.

**Chart 4**

**Pickering Forced Loss Rate**

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Avg |
|---|---|---|---|---|---|---|---|
| FLR (%) | 9.3 | 11.6 | 7.0 | 9.7 | 10.7 | 2.9 | 8.5 |

## Board Staff Interrogatory #85

**Issue Number: 5.1**
**Issue:** Is the proposed nuclear production forecast appropriate?

### Interrogatory

**Reference:**
Ref: Exh E2-1-1, Chart 2

Chart 2 shows OPG's historical production performance, as compared to its applied for and approved production forecast.

a) Does OPG perform any scenario analysis when preparing its nuclear production forecasts, i.e. preparing a range of forecasts with optimistic and pessimistic assumptions? If so, please provide the production forecasts for each scenario.

b) Does OPG perform any analyses to assess the expected statistical variability in its production forecasts? Is so, please provide such analyses.

c) What are the key elements/assumptions underpinning its proposed production forecast that pose the greatest risk to achieving its production goals?

d) Given OPG's history of not meeting its applied for and the OEB-approved production forecast, how would OPG characterize the assumptions in its proposed 2017-2021 production forecast (e.g. optimistic/aggressive, pessimistic/conservative)?

### Response

a) OPG does not perform any scenario analysis when preparing its nuclear production forecasts.

b) OPG does not perform any analysis to assess the expected statistical variability in its production forecasts as there is too much variability between outage program scope and duration to yield meaningful results.

c) The key risks to achieving the proposed production forecast are as follows:
   - Forced or unbudgeted planned outages to fix equipment
   - Human performance errors
   - Station fuel handling equipment issues that delay outage completion or cause unit derates
   - Emergent work that must be completed during an outage
   - Inspection results that extend planned outages
   - Outage delays due to resourcing issues

For discussion of other factors that could affect OPG's production forecast, see Ex. L-11.5-1 Staff-270.

d) OPG characterizes the assumptions in the proposed production forecasts as challenging, but achievable.

## Board Staff Interrogatory #84

**Issue Number: 5.1**
**Issue:** Is the proposed nuclear production forecast appropriate?

### Interrogatory

**Reference:**
Ref: Exh E2-1-2, page 5 – 8 Ref: Exh E2-1-2, Table 1
In the evidence, OPG has highlighted forced extensions to planned outage (FEPO) days as reasons for under-production as compared to the OEB-approved 2015 and 2014 production forecasts. In Table 1, OPG's Budget and OEB Approved production forecasts do not include any estimated value for FEPO.

a) Has OPG factored FEPO into its planned outage forecasts?

b) Has OPG undertaken any statistical analysis of historical trends in FEPO days? If so, please provide the analysis.

c) Do the lengths of the planned outages included in OPG's nuclear production forecast include any contingency days for unexpected delays in completion of projects? If so, what is used to calculate the appropriate number of contingency days to be included?

### Response

a) and c):

No, OPG does not directly factor FEPO or losses due to project delays into its planned outage forecasts. However, OPG assesses specific potential risks associated with an outage and assigns risk allowances associated with those risks to determine the outage duration. These risks in some cases are risks that had been identified as causing forced extensions to planned outages in the past. The number of days included in the outage plan for specific risks is based on the assessed consequential impact of the risk. The production forecast addresses overall risk to completion of the outage schedule. This methodology is consistent with the OEB approved approach in EB-2013-0321 (see Ex. E2-1-1, p. 2).

b) OPG does not perform a statistical analysis of the historical trends in the number of FEPO days. The number and scope of planned outages vary year over year, as well as the underlying cause for the FEPO and therefore the number of FEPO days cannot be trended over time. However OPG does complete post-outage analysis (referred to as a "common cause analysis") to assess, among other things, the reasons for a forced extension of a planned outage, with the intent to develop actions to prevent such occurrence in future outages.

# Board Staff Interrogatory #70

**Issue Number: 4.3**
**Issue:** Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

## Interrogatory

**Reference:**

Ref: Exh D2-2-9, Attachment 2 page 12
Ref: Exh D2-2-6, Attachment 1
The first reference states that "[t]he current assessment from the Defueling team shows the best case for defueling is 90 days, the most likely (i.e. P50) is 113 days, and the 90% confidence level duration is 134 days." The second reference shows the duration of Defueling as 113 days. OPG states in numerous locations in the evidence that it has a high level of confidence (P90) in the total DRP schedule.

Please explain the high level of confidence with the duration of the defueling of the unit (a critical path component) at 113 days.

## Response

Exhibit D2-2-6, Attachment 1, depicts the planned outage duration (target duration), and not the high confidence schedule. Similarly, the reference to 113 days in Ex. D2-2-9, Attachment 2, p. 12 refers to the target duration for the defueling activities, and not the high confidence duration. The high confidence duration for the defueling activities is 134 days and includes contingencies for risks. An example of one of these risks is that, should a Primary Heat Transport Pump fail, it would significantly affect the target duration for defueling. Therefore, this risk is included as one of the risks in the determination of the high confidence duration using OPG's methodology for calculating schedule contingency as described in Ex. D2-2-7.

OPG discusses the differences between the planned outage duration (target duration) and the high confidence schedule in Ex. D2-2-6, p. 5. Specifically, OPG states that it will manage day-to-day performance using the target duration, and that that schedule will be used to determine contractor incentives and disincentives.

## CCC Interrogatory #24

**Issue Number: 5.1**
**Issue:** Is the proposed nuclear production forecast appropriate?

### Interrogatory

**Reference:**
Reference: Ex. E2/T1/S1

Please list in table form all of the planned outages that are included in the test period forecast, the duration of each planned outage, the lost production resulting from each planned outage and the dollar value of each planned outage based on the proposed nuclear payment amount that would result if OPG is able to cancel the planned outage.

### Response

Please see Table 1 attached.

| Year | | Outage | Unit Affected | Description | Outage Duration (days) | Forecast Production (TWh) Impact Due to Outage | Revenue Impact of Outage ($M) |
|---|---|---|---|---|---|---|---|
| 2017 | Pickering | P1711 | Unit 1 | Planned Outage | 204.9 | 2.6 | 168.0 |
| | | P1742 | Unit 4 | Mid-Cycle Outage | 43.0 | 0.5 | 35.2 |
| | | P1751 | Unit 5 | Planned Outage | 160.7 | 2.0 | 132.0 |
| | | P1761 | Unit 6 | Planned Outage | 133.0 | 1.7 | 109.2 |
| | | **Total** | | | **541.6** | **6.8** | **444.4** |
| | Darlington | D1711 | Unit 1 | Planned Outage | 108.4 | 2.3 | 152.9 |
| | | DNRU2 | Unit 2 | Refurbishment Outage | 365.0 | 7.8 | 514.8 |
| | | D1731-PD | Unit 3 | Planned Derate | 2.5 | 0.1 | 3.5 |
| | | D1732 | Unit 3 | PHT Pump Motor Outage | 20.0 | 0.4 | 28.2 |
| | | D1741-PD | Unit 4 | Planned Derate | 2.5 | 0.1 | 3.5 |
| | | D1742 | Unit 4 | PHT Pump Motor Outage | 20.0 | 0.4 | 28.2 |
| | | **Total** | | | **518.4** | **11.1** | **731.2** |
| **Total 2017** | | | | | **1,060.0** | **17.9** | **1,175.6** |
| 2018 | Pickering | P1812 | Unit 1 | Mid-Cycle Outage | 43.0 | 0.5 | 39.1 |
| | | P1841 | Unit 4 | Planned Outage | 144.1 | 1.8 | 131.2 |
| | | P1871 | Unit 7 | Planned Outage | 193.5 | 2.4 | 176.4 |
| | | P1881 | Unit 8 | Planned Outage | 150.2 | 1.9 | 136.9 |
| | **Total** | | | | **530.8** | **6.6** | **483.6** |
| | Darington | D1811 | Unit 1 | PHT Pump Motor Outage | 20.0 | 0.4 | 31.3 |
| | | DNRU2 | Unit 2 | Refurbishment Outage | 365.0 | 7.8 | 571.4 |
| | | D1831 | Unit 3 | Planned Outage | 103.3 | 2.2 | 161.7 |
| | | D1841 | Unit 4 | PHT Pump Motor Outage | 20.0 | 0.4 | 31.3 |
| | **Total** | | | | **508.3** | **10.9** | **795.8** |
| **Total 2018** | | | | | **1,039.1** | **17.5** | **1,279.4** |
| 2019 | Pickering | P1911 | Unit 1 | Planned Outage | 128.5 | 1.6 | 129.8 |
| | | P1942 | Unit 4 | Mid-Cycle Outage | 43.0 | 0.5 | 43.4 |
| | | P1951 | Unit 5 | Planned Outage | 165.6 | 2.1 | 167.6 |
| | | P1961 | Unit 6 | Planned Outage | 180.1 | 2.2 | 182.3 |
| | **Total** | | | | **517.2** | **6.5** | **523.1** |
| | Darlington | D1911 | Unit 1 | PHT Pump Motor Outage | 20.0 | 0.4 | 34.8 |
| | | D1912-PD | Unit 1 | Planned Derate | 2.5 | 0.1 | 4.3 |
| | | DNRU2 | Unit 2 | Refurbishment Outage | 365.0 | 7.8 | 634.3 |
| | | P1931-PD | Unit 3 | Planned Derate | 2.5 | 0.1 | 4.3 |
| | | D1941 | Unit 4 | Planned Outage | 99.1 | 2.1 | 172.2 |
| | **Total** | | | | **489.1** | **10.5** | **850.0** |
| **Total 2019** | | | | | **1,006.3** | **16.9** | **1,373.1** |
| 2020 | Pickering | P2012 | Unit 1 | Mid-Cycle Outage | 43.0 | 0.5 | 48.2 |
| | | P2041 | Unit 4 | Planned Outage | 164.5 | 2.0 | 184.4 |
| | | P2071 | Unit 7 | Planned Outage | 102.5 | 1.3 | 115.1 |
| | | P2081 | Unit 8 | Planned Outage | 188.9 | 2.4 | 212.2 |
| | **Total** | | | | **498.9** | **6.2** | **560.0** |
| | Darlington | D2011 | Unit 1 | Planned Outage | 108.2 | 2.3 | 208.7 |
| | | DNRU2 | Unit 2 | Refurbishment Outage | 45.0 | 1.0 | 86.8 |
| | | D2022-PD | Unit 2 | Planned Derate | 2.5 | 0.1 | 4.8 |
| | | D2021 | Unit 2 | Post Refurb Mini Outage | 55.0 | 1.2 | 106.1 |
| | | DNRU3 | Unit 3 | Refurbishment Outage | 321.0 | 6.9 | 619.2 |
| | | D2042-PD | Unit 4 | Planned Derate | 2.5 | 0.1 | 4.8 |
| | | D2041 | Unit 4 | PHT Pump Motor Outage | 20.0 | 0.4 | 38.6 |
| | **Total** | | | | **554.2** | **8.6** | **773.6** |
| **Total 2020** | | | | | **1,053.1** | **14.8** | **1,333.5** |
| 2021 | Pickering | P2111 | Unit 1 | Planned Outage | 150.5 | 1.9 | 187.3 |
| | | P2141 | Unit 4 | Vacuum Building Outage | 30.0 | 0.4 | 37.3 |
| | | P2151 | Unit 5 | Planned Outage | 179.7 | 2.2 | 224.1 |
| | | P2161 | Unit 6 | Planned Outage | 112.6 | 1.4 | 140.4 |
| | | P2162 | Unit 6 | Vacuum Building Outage | 30.0 | 0.4 | 37.4 |
| | | P2171 | Unit 7 | Vacuum Building Outage | 30.0 | 0.4 | 37.4 |
| | | P2181 | Unit 8 | Vacuum Building Outage | 30.0 | 0.4 | 37.4 |
| | **Total** | | | | **562.8** | **7.0** | **701.3** |
| | Darlington | DNRU1 | Unit 1 | Refurbishment Outage | 200.0 | 4.3 | 428.3 |
| | | D2121 | Unit 2 | Post Refurb Mini Outage | 31.2 | 0.7 | 66.8 |
| | | D2122-PD | Unit 2 | Planned Derate | 2.5 | 0.1 | 5.4 |
| | | DNRU3 | Unit 3 | Refurbishment Outage | 365.0 | 7.8 | 781.6 |
| | | D2142-PD | Unit 4 | Planned Derate | 2.5 | 0.1 | 5.4 |
| | | D2141 | Unit 4 | PHT Pump Motor Outage | 20.0 | 0.4 | 42.8 |
| | **Total** | | | | **621.2** | **13.3** | **1,330.2** |
| **Total 2021** | | | | | **1,184.0** | **20.3** | **2,031.5** |

## Board Staff Interrogatory #096

**Issue Number: 6.1**
**Issue:** Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

### Interrogatory

**Reference:**
Ref: Exh F2-4-1 page 1
Outage OM&A cost for Darlington in the test period include, "outage costs for units laid up during refurbishment (e.g., Unit 2 during 2016-2020), which will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units."

a) Why are these inspection and maintenance activities separate from refurbishment?

b) What is the purpose of the aging and life cycle management programs for units undergoing refurbishment? Are the programs required by the CNSC? Please provide examples of aging and life cycle management programs.

### Response

(a) These inspection and maintenance activities are separate from refurbishment because they are required as part of the ongoing maintenance and operation of the plant and are required to be performed even while the unit is being refurbished.

Examples of these inspection and maintenance activities, which are typical of regular planned outages at Darlington or Pickering, are set out in OPG's response to part (b) below.

In contrast, Darlington Refurbishment Program ("DRP") scope is defined as the replacement of station life limiting components, regulatory and safety improvements and other work best performed during an extended refurbishment outage as well as incremental facilities and infrastructure required for DRP to complete the above scope.

(b) As identified above, the DRP has a defined scope of work limited to specific systems and components. The remaining systems and components not included as part of DRP scope require ongoing inspection, maintenance, repair and replacement as defined by station aging and life cycle management programs for those systems and components.

The purpose of these programs is to ensure equipment is meeting safety and reliability standards and requirements. Some programs are required by the CNSC, which typically include periodic inspections and preventative maintenance programs on safety related equipment. Some investments are required to ensure the plant runs optimally and meets performance expectations. Examples of maintenance activities as per the stations aging and life cycle management programs are as follows:

- Replacement of system components at end of component life before failure
- Replacement of obsolete parts; e.g., plant computer equipment
- Overhauls of pumps and valves
- Preventative maintenance on motors
- Inspections of heat exchanger tube bundle wall thickness
- Inspection and testing of electrical circuit breakers
- Calibration of instrumentation.

## Board Staff Interrogatory #97

**Issue Number: 6.1**
**Issue:** Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

### Interrogatory

**Reference:**
Ref: Exh F2-4-1 page 1
Ref: Exh E2-1-1 page 3
The evidence at Exh F2-4-1 states that, "Darlington Unit 2 is scheduled to return to service in February 2020 following refurbishment. OPG has scheduled two post refurbishment mini planned outages to address any issues expected to arise after the major refurbishment is complete and the unit has resumed operations."

The evidence at Exh E2-1-1 states that, "The need for these post-refurbishment outages is based on operating experience at other nuclear facilities that underwent major refurbishment."

What is the cost of each of the mini planned Darlington Unit 2 outages?

### Response

The estimated cost of the first mini post-refurbishment planned outage is $12.8M and the second $8.2M. The second mini-outage is estimated to cost less due to the shorter duration and expected smaller scope.

# Board Staff Interrogatory #98

**Issue Number: 6.1**
**Issue:** Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

## Interrogatory

**Reference:**
Ref: Exh F2-4-1 page 7

The evidence states, "For Pickering, a station-wide VBO is required every 11 years, with the most recent occurring in 2010 and the next scheduled for 2021. Pickering's outage OM&A expenditures in 2020 include costs for preparatory work for the 2021 VBO and the outage OM&A forecast in 2021 includes expenditures associated with a six unit VBO."

a) Please confirm that the outage OM&A expense for 2020 related to VBO would not be included in the forecast without the Pickering extended operations proposal.

b) If Pickering extended operations does not proceed, please confirm that the 2021 VBO would not be undertaken. Please confirm that the revenue requirement impact of any VBO costs underpinning payment amounts would then be credited to the capacity refurbishment variance account.

c) Please provide a table summarizing all the 2020 and 2021 VBO costs, including details for Pickering station and nuclear support division costs.

d) Are any of the costs set out in (b) also included in Exh F2-4-1 Chart 2, Pickering Extended Operations Outage OM&A?

e) Please provide the same table as set out in (b) for the Q2 2010 Pickering VBO. Please explain any differences in costs.

## Response

a) Confirmed. For planning purposes, OPG assumed that the Vacuum Building outage as dictated by Canadian Safety Standards would not be required if operations were to cease in 2020.

b) As noted in part (a), if Pickering ends commercial operations in 2020, then OPG would seek approvals to not execute the VBO currently planned in 2021. As explained in Ex. L-05.1-1 Staff 87(c), the VBO is dictated by Canadian Safety Standards (CSA) N287.7 and undertaken pursuant to CNSC licence conditions. It is part of the normal periodic station inspection and testing activity.

OPG does not confirm that the revenue requirement impact of any VBO costs underpinning payment amounts would be credited to the Capacity Refurbishment Variance Account. As discussed in Ex. L-6.9-1 Staff 178(c), only expenditures to increase the output of, refurbish or add operating capacity to a prescribed generation facility fall within the definition of the CRVA pursuant to O. Reg. 53/05. Since the VBO does none of these things, any changes in VBO costs would not be captured within the CRVA.

c) The incremental budget for the VBO is $46M. The total amount has been budgeted in 2021 under the Pickering total found in Ex. F2-4-1 Table 1, Line 2. There currently are no VBO preparation costs included in the 2020 forecast. The final scope has not been defined and accordingly preparatory expenditures could not be distributed. When the final scope is defined, costs will be distributed between the station and support departments and an appropriate share allocated for preparations in the years preceding execution.

d) Refer to part (c). There are no VBO costs included in 2020 in Ex. F2-4-1, p. 2, Chart 2.

e) Chart 1 below provides a summary of incremental costs associated with the 2010 VBO compared to the 2021 budget as described in part (c). Total incremental costs are on par with the 2010 VBO assuming a 2% escalation factor. As stated in part (c) above, the 2021 VBO scope has not been finalized. Therefore, an explanation of differences in costs cannot be provided.

Chart 1

| Organization | 2010 VBO Actual Costs | 2021 VBO Budget |
|---|---|---|
| Pickering Nuclear | 29.7 | 46.2 |
| Support Organizations | 5.9 | Not available |
| **Total ($M)** | **35.7** | **46.2** |

## SEP Interrogatory #9

**Issue Number: 6.2**
**Issue:** Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

### Interrogatory

**Reference:**
**Ref Exh F2-1-1, p21 Ins14-19 Workforce Planning and Resourcing Initiative**

a) Please outline the fleet-wide resourcing strategy that is being implemented with this initiative.

### Response

In recognition of the need to recruit staff into the organization, and concurrently manage the impact of Pickering End of Commercial Operations (PECO), integrated long term fleet staffing plans are required to ensure sufficient resources are available for safe and reliable operation, while minimizing cost post-PECO.

The resourcing strategy's goal is to establish a long-term staffing overview for key functional areas (operations, maintenance and engineering) that manage the allocation of resources across the nuclear fleet. These staffing plans optimize the resources between sites within key functional areas, and provide the input for yearly external recruitment of staff.

# Board Staff Interrogatory #109

**Issue Number: 6.2**
**Issue:** Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

## Interrogatory

**Reference:**
Ref: Exh F2-1-1 Attachment 2 page 3 and 11 Ref: Exh F4-3-1 Attachment 1

At page 3, it states, "We benchmarked 5,421 OPG Nuclear staff and long-term contractors; 2,036 OPG Nuclear personnel could not be benchmarked."

a) Confirm that these data units are FTE, as used in the balance of the Goodnight report.

b) What is the definition of long-term contractor? What is the equivalent term used by OPG?

c) The total nuclear staff referred to by Goodnight is 7,457 FTE, presumably at March 2014. Attachment 1 to Exh F4-3-1 is a table summarizing FTE for the period 2013 to 2021. The total actual nuclear FTE for 2014 are 8,431.8.
   i. At page 11, Goodnight states that an FTE is 1,890 hours/year (or 36-1/3 hours per week). What factor did OPG use to determine FTE in Attachment 1 to Exh F4-3-1?
   ii. While the FTE data were collected at different times in 2014, please explain the approximately 1,000 FTE difference between the 7,457 FTE referred to in the Goodnight study and the 8,431,8 FTE summarized in Attachment 1 to Exh F4-3-1.
   iii. Using the same categories as lines 3 to 22 Attachment 1 to Exh F4-3-1, please set out the distribution of the 5,421 FTE that were benchmarked by Goodnight.

## Response

a) Goodnight data is a combination of regular staff headcount translated into FTEs and long-term contractor FTEs at March 2014.

b) Goodnight Consulting defines a long-term contractor as non-regular staff or purchased services contractors of 6 months or longer duration (Goodnight report at EB-2013-0321 Ex. F5-1-1 Part a, p. 39). OPG does not distinguish between short term and long term contractors in its contractor support services (see definition of non regular labour, augmented staff and other purchase services in Ex. F2-4-1, p. 4).

c) Goodnight refers to 7,457 FTEs, which represent 6,926 regular staff, 195.3 non-regular staff contractor FTEs and 335.7 purchased services contractor FTEs.

i. More specifically, Goodnight is referring to an annual factor of 1,890 hours per year to calculate FTEs for purchased services contractors.

The FTEs in Attachment 1 to Ex. F4-3-1 were determined based on the weekly base hours associated with each position over the course of the year. Different factors were used depending on the base hours of work associated with each regular staff position as follows:

- For an employee whose base hours of work are 35 hours per week, an annual factor of 1,820 hours per year was used

- For an employee whose base hours of work are 37.5 hours per week, an annual factor of 1,950 hours per year was used

- For an employee whose base hours of work are 40 hours per week, an annual factor of 2,040 hours per year was used

ii. The difference of 974.8 FTEs from the 7,457.0 Nuclear FTEs in the Goodnight study to the 8,431.8 actual FTEs for 2014 in Ex. F4-3-1 Attachment 1 is due to the following:
   - Timing difference:
     - Goodnight is based on regular staff headcount as of March 2014 and long-term contractor FTEs in role from April 2013 to March 2014. Ex. F4-3-1 Attachment 1 includes FTEs for the year.
   - Scope differences:
     - Goodnight includes 335.7 benchmarked contractor FTEs derived from purchased services which are not in included in Ex. F4-3-1 Attachment 1 as they are not regular staff.
       - Goodnight excluded various FTES in its study as follows:
         - 2,036 Regular FTEs which could not be benchmarked, primarily due to supporting CANDU technology (e.g., fuel handling, heavy water management, tritium removal), outage execution, nuclear waste and used fuel processing, or refurbishment planning.
         - Security staff (not benchmarked consistent with OPG Security policy)
         - Non-regular staff of less than 6 months duration or students
         - Corporate staff who do not directly support Nuclear

iii. Of the 5,421 FTEs benchmarked by Goodnight, these include 335.7 purchased services contractor FTEs, which are not represented in Ex. F4-3-1 Attachment 1. Therefore, 5,085.3 regular and non-regular benchmarked FTEs can be distributed according to the format of Ex. F4-3-1 Attachment 1 lines 3 to 22:

| Line No. | NUCLEAR FACILITIES | Goodnight 2014 Study Benchmarked |
|---|---|---|
| | | |
| 1 | **Staff** (Regular and Non-Regular) | **FTEs** |
| 2 | | |
| 3 | **Nuclear - Direct** | |
| 4 | Management | 271.2 |
| 5 | Society | 1,281.3 |
| 6 | PWU | 2,335.7 |
| 7 | EPSCA | 42.5 |
| 8 | Subtotal | 3,930.7 |
| 9 | | |
| 10 | **Nuclear - Allocated** | |
| 11 | Management | 148.0 |
| 12 | Society | 335.7 |
| 13 | PWU | 671.0 |
| 14 | EPSCA | 0.0 |
| 15 | Subtotal | 1,154.6 |
| 16 | | |
| 17 | **NUCLEAR FACILITIES** | |
| 18 | Management | 419.2 |
| 19 | Society | 1,617.0 |
| 20 | PWU | 3,006.6 |
| 21 | EPSCA | 42.5 |
| 22 | Total | 5,085.3 |
| | | |
| | **Contractor FTEs Purchased Services** | 335.7 |
| | **Total** | 5,421.0 |

## Board Staff Interrogatory #110

**Issue Number: 6.2**
**Issue:** Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

### Interrogatory

**Reference:**
Ref: Exh F2-1-1 Attachment 2 page 13 and 28
Ref: EB-2010-0008 Undertaking J5.3
Ref: Exh F2-1-1 Attachment 4 page 12

Goodnight contacted CANDU operators globally and received no data to contribute to the study and was therefore unable to benchmark data for CANDU-specific activities. Through "technical adjustments" of PWR operator data, Goodnight determined that the appropriate CANDU benchmark was 5,208 FTE.

In response to undertaking J5.3 in the 2011-2012 payment amounts proceeding, OPG provided minimum complement data as set out in operating licences. Based on 5 shifts, the minimum complement for Darlington was 475 people and for Pickering was 630 people.

a) Are the minimum complement data based on headcount or FTE?

b) Have the minimum complement data changed since undertaking J5.3 was filed? If yes, what are they currently for Pickering and Darlington?

c) At Exh F2-1-1 Attachment 4 page 12, it states that the Days Based Maintenance initiative required CNSC approval as the minimum complement staffing number changed. What was the change in staffing number related to this initiative?

d) What are the CNSC minimum complement data for:
   i. An operational 4 unit Pickering facility
   ii. A non-operational Pickering facility
   iii. A Darlington facility with one unit under refurbishment
   iv. A Darlington facility with two units under refurbishment

**Response**

a) The minimum complement is based on headcount.

b) Yes, the minimum complement data has changed since undertaking J5.3 was filed in EB-2010-0008.

The Pickering minimum complement is currently 67 (previously 84) per shift with additional staff required during fuelling activities on a unit or if the heavy water upgrader is required to be operating.

The Darlington Minimum complement is currently 54 (previously 57) per shift when no fuel handling trolleys are being operated and 58 (previously 61) per shift when all three fuel handling trolleys are being operated.

c) The Days Based Maintenance initiative resulted in a net reduction of four minimum complement positions per shift at Darlington and 15 minimum complement positions per shift at Pickering. In addition, four of the minimum complement roles at each station were changed to only be required on 12 hour days (i.e., position is not required to be filled on night shift).

d) The CNSC does not prescribe minimum complement numbers. Rather, they are derived by the licensee based on the most resource-intensive conditions under all operating states, design basis accidents, and emergencies. The CNSC must accept any changes to minimum complement proposed by the licensee prior to implementation of those changes.

Related to the future reduction of operational units at Pickering, OPG expects to propose changes to the minimum shift complement as justified by changes to credible accidents, emergency situations, and operating states; however, the number of staff and related station conditions have not been determined at this time.

For Darlington, OPG has not proposed a reduction in minimum complement staff number for units under refurbishment as these staff are still required for monitoring and control of the units, although there has been a request accepted by the CNSC to reduce qualification requirements for operations staff monitoring the defueled unit in the control room.

# UNDERTAKING J5.3

## *Undertaking*

To provide minimum complement summary for different categories for Darlington and Pickering.

## *Response*

The Pickering minimum complement is 84 people. This is documented in the extract from the Pickering Nuclear Power Reactor Operating Licence provided at page 1 of Attachment 1.

The Darlington minimum complement is 57 people when no fuel handling trolleys are being operated, or 61 people when all three fuel handling trolleys are being operated. Note that the capability to operate three trolleys is required for long term operation. The Darlington minimum complement is documented in the extract from the relevant Darlington procedure, which is referenced in the Darlington Nuclear Power Reactor Operating Licence and provided at page 2 of Attachment 1.

The minimum complement is the minimum number of people that must be on site at all times as required by CNSC licensing.

In order to ensure that the licensed minimum is always met, OPG uses five rotating shift crews and must cover for vacation, training and illness.

The number of people needed to cover the minimum complement at Pickering is approximately 630 people.

The number of people needed to cover the minimum complement at Darlington is approximately 475 people.

**Board Staff Interrogatory #93**

**Issue Number: 6.1**
**Issue:** Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?

## Interrogatory

**Reference:**
Ref: Exh F2-3-3 Attachment 1 Tab 4
This BCS relates to the Fuel Channel Life Extension (FCLE) Project (Project # 10- 80014). The BCS is identical to the BCS previously filed under EB-2013-0321 (Exh F2- 3-3, Attachment 1, Tab 11). The BCS is a partial-release BCS, approved on 2013-11- 11, to fund Phase 1 of the FCLE project during 2014 and 2015. The BCS states that another CANDU operator will co-fund the R&D effort at 50% (page 3).

a) Please provide an update on the project schedule and cost including whether Phase 1 was completed and whether the estimated total project cost, including the non- OPG CANDU operator's share, is still $105.8M including contingency.

b) It is noted that OPG received Canadian Nuclear Safety Commission (CNSC) approval in November 2015 to operate the Darlington units up to the proposed refurbishment outages, to a maximum of 235,000 EFPH (Equivalent Full Power Hours). Please confirm that the idle time (estimated at 57 months) on the last 3 Darlington units to be refurbished (refer to Figure 1 of BCS, page 2) has been eliminated.

c) What is the status of the project's objective and/or confidence level to achieve fuel channel fitness-for-service of at least 261,000 EFPH for Pickering?

## Response

a) In the partial release approved on November 11, 2013, OPG estimated the total project cost inclusive of industry shared work to be $105.8M with OPG's costs estimated at $67.4M. OPG's cost of $67.4M can be divided into two distinct scopes of work: OPG-specific work and industry-shared R&D work. The $67.4M estimate was based on best available information and prior to partnership arrangements being finalized for the shared scope of work.

OPG's current best estimate of the total project cost (inclusive of industry shared work) is $97M (including contingency), with OPG's share being $69.3M (see L-6.1-1 Staff-93 Attachment 1 which includes confidential content as marked). This revised total project cost does not include industry partner internal costs, which are not available to OPG.

As noted, a component of OPG's share of $69.3M includes industry shared R&D work. Partnership agreements are now in place for the industry-shared scope of R&D work and OPG's share for this portion of work is 47.5%.

Significant testing has been completed with respect to Burst Tests, pressure tube fracture toughness testing, material property testing of pressure tubes, fatigue crack initiation testing, crush and fatigue testing of Darlington spacers etc. Phase I work is scheduled to be completed in 2017 with project completion expected in 2020.

b) Confirmed. The idle time that was estimated on the last three Darlington units to be refurbished (see L-6.1-1 Staff-93 Attachment 1, p. 2, Figure 1) has been eliminated.

c) OPG is highly confident of continued safe operation of Pickering fuel channels for operation to the target service life of December 2020 based on its ongoing assessment of fuel channel fitness for service and interactions with CNSC staff.

ONTARIO POWER GENERATION

Records File Information: Records SCI/USI Retention - See Guidance Section

**OPG - Confidential**

OPG-FORM-0076-R005*

# Type 3 Business Case Summary

To be used for investments/projects meeting Type 3 criteria in OPG-STD-0076.

## Executive Summary and Recommendations

| **Project Information** | | | |
|---|---|---|---|
| **Project #:** | Project # 10-80014 | **Document #:** | N-BCS-31100-10009 R01 |
| **Project Title:** | Fuel Channel Life Extension Project | | |
| **Class:** | ☒ OM&A ☐ Capital ☐ Capital Spare<br>☐ MFA ☐ CMFA ☐ Provision<br>☐ Others: | **Investment Type:** | Value Enhancing |
| **Phase:** | Execution | **Release:** | Full |
| **Facility:** | Nuclear | **Target In-Service or Completion Date:** | December-2020 |

**Project Overview**

**DECISION REQUIRED**

The purpose of this submission is to request Board of Directors approval of the full execution release (Gate 3) of the Fuel Channel Life Extension Project in the amount of $28.1 million, for a total release of $69.3 million (including [redacted] contingency).

**ISSUE**

The project was first approved in 2013 for $105.8 million based on a Class 4 estimate (+50%, -15%). The project is now estimated at $69.3 million (including [redacted]) based on a Class 3 estimate (+20%, -15%). Board of Directors approval is required for projects exceeding $40 million.

**ANALYSIS**

OPG needs to continually update its assessments of degradation mechanisms on fuel channel components. These degradation mechanisms impact OPG's ability to demonstrate fitness-for-service of the units and continue to operate these units to planned end of life.

Understanding of fuel channel component degradation mechanisms has been improved by the research and development work and technical assessments co-ordinated under the completed Fuel Channel Life Management Project. Plans, tools, and methodologies were developed for assessing technical confidence in the fitness-for-service of Darlington pressure tubes to 210,000 effective full power hours and Pickering to 247,000 effective full power hours.

There is economic value in increasing the effective full power hour limits for both Darlington and Pickering. Darlington refurbishment requires that the three units with overlapping outages operate up to approximately 235,000 effective full power hours. Extended operation of all Pickering units to year end 2020 would require operation life of 261,000 effective full power hours. A separate project – Pickering Fuel Channel Life Assurance – is in progress to extend the life of the Pickering fuel channels to 2024.

The project objective is to issue Technical Confidence Statements on fuel channel fitness-for-service to 235,000 and 261,000 effective full power hours for Darlington and Pickering units respectively. The Confidence Statements will be based on the results on a number of research and development topics that have direct impacts on constituent parts of fitness-for-service statements.

The $36.5 million reduction in the cost of the project is driven primarily by Bruce Power co-funding of the project [redacted] and reduced contingency [redacted] offset by increases due to scope changes ($0.8 million) and vendor cost increases ($7.8 million). While the contingency is reduced due to the retirement of two risks, the remaining contingency is comparatively high for a Class 3 estimate due to a newly identified risk.

The original estimate of $105.8 million (including [redacted]) was based upon OPG funding the full extent of the research and development project managed by the CANDU Owners Group. Following the approval in 2013, Bruce Power agreed to co-fund of the programme, thereby reducing OPG's investment.

# Type 3 Business Case Summary

Project #: Project # 10-80014
Document #: N-BCS-31100-10009 R01
Project Title: Fuel Channel Life Extension Project, Full Release

| Project Cash Flows, NPV, and OAR Approval Amount | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| M$ | 2015 LTD | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Future | Total |
| Currently Released | 14.9 | 15.4 | 10.9 | | | | | | 41.2 |
| Requested Now | - | | 2.7 | 14.4 | 9.3 | 1.7 | | | 28.1 |
| Future Required | - | | | | | | | | |
| **Total Project Cost** | 14.9 | 15.4 | 13.6 | 14.4 | 9.3 | 1.7 | | | 69.3 |
| Ongoing Costs | 1.0 | 0.3 | 8.0 | 31.6 | 57.6 | 14.4 | 7.5 | | 120.3 |
| **Grand Total** | 15.9 | 15.7 | 21.6 | 46.0 | 66.9 | 16.1 | 7.5 | | 189.6 |
| **Estimate Class:** | Class 3 | | | **Estimate at Completion:** | [redacted] | | | | |
| **NPV:** | $700M | | | **OAR Approval Amount:** | $189.6M | | | | |

**Additional Information on Project Cash Flows (optional):**

Project Cash Flows, Estimate at Completion, and OAR approval amount show in the table above assumes co-funding by any other party. The Estimate at Completion does not include contingency of [redacted]

Ongoing Costs are composed of Consequential costs and contingency Single Fuel Channel Replacements (SFCR):

| $M | To Enable 261k EFPH for Pickering | To Enable 235k EFPH for Darlington | Total |
|---|---|---|---|
| Consequential Costs* | 39.9 | 56.4 | 96.3 |
| Contingency SFCR (including material surveillance) | | 24 | 24 |
| Total | 39.9 | 80.4 | 120.3 |

*Consequential costs are composed of: material surveillance of pressure tubes and spacers beyond P1671 SFCR, incremental station OM&A for fuel channel inspection and maintenance, incremental major components (Steam Generators) life cycle management costs, spacer material and ex-service spacer irradiation in High Flux Isotope Reactor, and potential additional burst tests to improve fracture toughness models at Heq<120PPM.

Note: This BCS assumes that OPG's partners in JP #4491 continue to co-fund the R&D effort at their current contribution levels. This assumption is based on COG JP #4491 partner approvals.

| Approvals | Signature | Comments | Date |
|---|---|---|---|
| The recommended alternative, including the identified ongoing costs, if any, represents the best option to meet the validated business need. | | | |
| **Recommended by (Project Sponsor):** Glenn Jager, President, OPG Nuclear and CNO | [signature] | | 27 JULY 2016 |
| I concur with the business decision as documented in this BCS. | | | |
| **Finance Approval:** Ken Hartwick, SVP & Chief Financial Officer per OPG-STD-0076 | [signature] | | Aug 9, 2016 |
| I confirm that this project, including the identified ongoing costs, if any, will address the business need, is of sufficient priority to proceed, and provides value for money. | | | |
| **Approved by:** Jeffrey Lyash, President & Chief Executive Officer per OAR 1.11.11.1 | [signature] | | Aug 10/16. |

# Type 3 Business Case Summary



**Part B: Preferred Alternative: Execution of Fuel Channel Life Extension Project**

**Description of Preferred Alternative**

**Table 2** below explains the differences between FCLM (#62444) and this project (#80014) on the Core R&D scope items:

| Item | FCLM Scope (Proj. #62444) | FCLE Scope (Proj. #80014) | Explanation |
|---|---|---|---|
| 1. Fracture Toughness - Burst Tests | 14 BTs has been completed with which Rev. I of the New Fracture Toughness (FT) models have been established. | The original test matrix recommended 17 to 50 BTs (including 6 from FCLM that will be credited towards the matrix). This BCS assumes funding for 10 additional BTs. | Additional BTs are required to test PT and spacer material with high [Heq], broader range of Chlorine concentrations and higher hoop stress conditions which would exist during the extended life. CNSC is closely scrutinizing the BT test matrix for granting acceptance of the new fracture toughness model. |
| 2. Hydriding Techniques Development | High Pressure Hydriding target of 120 ppm [Heq] | Alternate Hydriding method has been included in parallel to HPH method for achieving 150 ppm [Heq]. | HPH repeatability has been poor and may not achieve the target [Heq]. Alternative processes are required to support DNGS refurbishment planning. The very recent results from alternate hydriding at small scale have shown success. |
| 3. Spacer HFIR Irradiation | HFIR piloting i.e. reactor set up, material procurement, shipping and testing of the samples removed from the first interval. | Irradiation (Neutron) cost of subsequent samples and ex-service spacers retrieved during SFCRs. | Oak Ridge National Laboratories (ORNL) did not charge for neutrons during FCLM scope which was considered R&D work. Significant neutron charges will now be levied for future OPG commercial orders. |
| 4. Spacer Empirical & Structural Modelling | Initial development of the models | Refinement of the models and acceptance by CNSC | These models are required to predict the life of the DNGS tight fitting spacers. |

**PROJECT COMPLETION**

Project is targeted for completion and close-out by December 2020. A PIR will be completed by December 2021.

**Deliverables under this release (2016-2020):**

| Deliverables: | Associated Milestones (if any): | Target Date: |
|---|---|---|
| Confirmatory technical confidence statement for PNGS 261k EFPH | | 30/06/2017 |
| Updated Spacer Engineering Structural Model | | 30/11/2017 |
| Develop Hydriding Techniques to Achieve High [Heq] (up to 150 ppm) | | 29/12/2017 |
| Technical Confidence Statement (235k EFPH for DNGS) if needed | | 30/06/2018 |
| Confirmatory technical confidence statement for DNGS 235k EFPH | | 30/06/2020 |
| Project Close-out | | 15/12/2020 |