**Ontario Energy Board**

P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie de l'Ontario**

C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

**BY E-MAIL**

September 26, 2016

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

Dear Ms. Walli:

**Re: Ontario Power Generation Inc.**
**2017-2021 Payment Amounts**
**Ontario Energy Board File Number EB-2016-0152**

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories relating to the above noted proceeding. OPG and all intervenors have been copied on this filing.

Yours truly,

*Original signed by*

Violet Binette
Project Advisor, Applications

Attach

**OEB Staff Interrogatories**
**Ontario Power Generation Inc. (OPG)**
**2017-2021 Payment Amounts**
**EB-2016-0152**
**September 26, 2016**

## GENERAL

### Issue 1.1
**Has OPG responded appropriately to all relevant OEB directions from previous proceedings?**

### Issue 1.2
**Are OPG's economic and business planning assumptions that impact the nuclear facilities appropriate?**

#### 1.2-Staff-1
<u>Ref: Exh A1-4-1 Attachment 2</u>
Attachment 2 is the Memorandum of Agreement between the Shareholder and OPG, dated July 17, 2015.

a) The previous memorandum was dated August 17, 2005. Under what circumstances is the memorandum revised?
b) What circumstances required the July 17, 2015 revision?
c) Please summarize the differences between the August 17, 2005 and July 17, 2015 memoranda.

#### 1.2-Staff-2
<u>Ref: Exh A2-1-1, Attachment 3, Page 120</u>
OPG received exemptive relief from the Ontario Securities Commission requirements to allow it to file consolidated financial statements based on US GAAP without becoming a US Securities and Exchange Commission registrant or issuing public debt. This exemption was received in the first quarter of 2014 and is effective until the earlier of January 1, 2019, the year after OPG ceases to have rate regulated activities or the date the International Accounting Standards Board prescribes the mandatory application of an IFRS standard to rate regulated entities.

a) Please explain OPG's plans when any of these conditions are met with respect to the accounting standard to be used going forward.
b) Please explain the potential rate setting impact since at least one of these conditions will be met during OPG's test period (i.e. January 1, 2019).

#### 1.2-Staff-3
<u>Ref: Exh A2-2-1, Attachment 2</u>
The 2016-2018 Business Planning Instructions are dated May 29, 2015. Have the 2017-2019 Business Planning Instructions been issued? If yes, please provide a copy.

**1.2-Staff-4**
Ref: Exh A1-6-1
Ref: Exh C2-1-1 Table 1
Tab 6 of Exhibit A1 summarizes legislative framework. With respect to the OEB Act and O. Reg. 53/05, the evidence states, "The combination of the Act and the Regulation provide that OPG is entitled to receive just and reasonable payments, subject to specific rules in the Regulation, with respect to the output from the prescribed generating facilities."

Section 6(2)8 of O. Reg. 53/05 states that, "The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan." In the current application, the 2017 forecast nuclear liability revenue requirement impact is $144.9M of the total $3,189.9M nuclear revenue requirement for 2017.

Please itemize all the aspects of the 2017 revenue requirement that are "subject to specific rules in the Regulation." Please respond in a format similar to the above paragraph regarding nuclear liabilities.

**Issue 1.3**
**Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?**

**1.3-Staff-5**
Ref: Exh A1-3-3, page 2
OPG's rate smoothing proposal in this application results in a $1.05 increase on the total monthly residential customer bill each year, while the unsmoothed scenario would result in a $1.85 increase.

Please provide a summary of the calculations for these two scenarios.

**RATE BASE**

**Issue 2.1**
**Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?**

**2.1-Staff-6**
Ref: Exh B1-1-1 Chart 1
a) Please update the 2016 budget for the most recent available actuals. (Please update DRP costs in this Chart, as well).
b) Chart 1 shows 2016 forecast of support services capital projects entering rate base of $10.5M and Exh D3-1-2 Table 5, lines 7 and 9 shows $8.5M+$5.1M=$14M. Similarly, for 2018 Chart 1 shows $18.0M and Table 5 shows $18.8. Please explain the difference and/or update the evidence.

**2.1-Staff-7**

Ref: Exh B3-3-1 Table 1

Please see the following chart of Total Nuclear In-service Capital additions without ARC or DRP for 2013-2015 with the sources of the information. The 2013-2015 Nuclear Operations totals do not agree with the totals in Exhibit B3-3-1 Table 1 when DRP is excluded. Please explain or update the evidence.

| (in millions) | 2013 Actual | 2014 Actual | 2015 Actual | Source |
|---|---|---|---|---|
| In-service Capital Additions | $193.4 | $125.8 | $181.8 | D2-1-3 Table 4, line 4 |
| | | | | |
| Minor Fixed Assets | $10.2 | $22.9 | $22.3 | D2-1-3 Table 4, line 7 |
| Support Services | $3.7 | $1.8 | $2.9 | Exhibit D3-1-2 Table 5 lines 1,3,7,9,13,15 |
| TOTAL Nuclear Operations Capital | $207.3 | $150.5 | $207.0 | |
| | | | | |
| **TOTAL NUCLEAR CAPITAL ADDITIONS (excluding DRP and ARC)** | **$214.5** | **$228.1** | **$216.5** | Exhibit B3-3-1 Table 1, net change |

**Issue 2.2**

**Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?**

**2.2-Staff-8**

Ref: Exh D2-2-10, page 23 and Table 5

The following table shows the budgeted, actual and approved in-service additions to rate base for the DRP:

| (in millions) | 2013 Budget | 2013 Actual | 2014 Approved | 2014 Actual | 2015 Approved | 2015 Actual | 2016 Budget | 2017 Proposed | 2018 Proposed | 2019 Proposed | 2020 Proposed | 2021 Proposed |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DRP | 104.2 | $99.2 | $18.7 | $43.5 | $143.4 | $147.1 | $350.4 | $374.4 | $8.9 | $0.0 | $4,809.2 | $0.4 |
| | | | | | | | | | | | | |
| Note: in 2015 approved capital in-service additions were 209.2 however $66M was for OSB andAHS which were moved to Nuclear Operations | | | | | | | | | | | | |
| Source: Exhibit D2-2-10 Table 5 | | | | | | | | | | | | |

The referenced evidence explains that 2014 and 2015 actual in-service additions were greater than approved due to a number of projects being advanced or delayed.

a) In the Decision with Reasons for EB-2013-0321, the OEB approved $18.7M for 2014 for the projects listed below. In explaining the 2015 Actual versus 2015 OEB Approved variances, OPG details the following variances for each of the projects. Please complete the following table by providing the actual in-service addition amounts. If there are other projects not included in the list, please provide details.

| Project | Approved in Service | Variance | Actual |
|---|---|---|---|
| Water & Sewer | $12.2M | +$10.7M from 2013 | ? |
| Elec. Power Distribution System | $4.4M | -$4.4M | $0 |
| Other Station Modifications | $2.1M | -$2.1M | $0 |
| Heavy Water Facility related | | +$14.6 | ? |
| Vehicle Screening Facility | | +$4.1M | ? |
| Other projects? | | | ? |
| Total | $18.7M | $22.9M | $43.5M |

b) In the Decision with Reasons for EB-2013-0321, the OEB approved $209.4M-$66M =$143.4M for 2015 for the projects listed below. Please complete the following table as per part a) above.

| Project | Approved in Service | Variance | Actual |
|---|---|---|---|
| D2O Storage | $83.5M | -$83.5M | $0M |
| Elec. Power Distribution System | $6.2M | +$9.3M | ? |
| Safety Improvement Opportunities | $42.7M | | ? |
| Other Station Modifications | $11.1M | | ? |
| Refurbished Project Office and Retube and Feeder Replacement Island Support Annex | | +$96M | ? |
| Emergency Power Generator, Containment Filtered Venting System, Islanding D2O Management System | | -$36M | ? |
| Powerhouse Steam Venting System, Emergency Service Water Buried Services | | +$18M | ? |
| Other projects? | | | ? |
| Total | $143.4M | $3.8M | $147.1M |

c) In the Decision with Reasons for EB-2013-0321, the approved $18.7M and $143.4M (after adjustment) for DRP were identified as campus plan projects i.e. facilities and infrastructure. The Decision also stated that "[t]he Board has considered this evidence and agrees that the campus plan projects described are useful to the on-going operations of Darlington." Please explain why some campus plan projects are considered to be part of the DRP while others are part of Nuclear Operations.

**2.2-Staff-9**
<u>Ref: Exh D2-2-10, Table 5</u>
<u>Ref: Exh D2-2-4, Figure 1</u>

The first reference above shows in-service capital additions for the DRP. In EB-2013-0321, Exhibit L, Tab 4.9, Schedule 1, Staff-048, OPG provided the following Chart:

| DRP projects wholly or partially in service in the test period ($millions) | Final In service year | Partial in-service years | Projected Total Capital Expenditure | Amount in 2014 Rate Base | Amount in 2015 Rate Base | Dep'n in 2014 Rev Req[1] | Dep'n in 2015 Rev Req[1] | Amount recorded in Capacity Refurb Variance Acct (Dec. 2013) *[2] |
|---|---|---|---|---|---|---|---|---|
| Darlington Energy Complex | 2013 | | 105.4 | 92.0 | 89.6 | 2.4 | 2.4 | 6.8 |
| Water and Sewer Project | 2014 | 2012, 2013 | 36.0 | 20.8 | 26.4 | 0.4 | 0.6 | 1.5 |
| Heavy Water Storage & Drum Handling Facility | 2015 | | 108.1 | - | 20.3 | - | 1.1 | - |
| Darlington Operations Support Building Refurb | 2015 | | 46.8 | - | 14.6 | - | 0.4 | - |
| Auxiliary Heating System | 2015 | | 45.6 | - | 17.9 | - | 0.5 | - |
| Electrical Power Distribution System | 2015 | 2014 | 17.8 | 2.2 | 7.3 | 0.1 | 0.2 | 0.1 |
| Powerhouse Steam Venting System | 2015 | | 10.2 | - | 5.0 | - | 0.1 | - |
| Third Emergency Power Generator Project | 2015 | | 32.5 | - | 16.0 | - | 0.4 | - |
| Container Venting System Project | | | - | - | - | - | - | - |
| Other Miscellaneous Projects | | 2014, 2015 | 13.2 | 1.0 | 7.5 | 0.0 | 0.2 | - |
| **TOTAL** | | | **415.4** | **116.0** | **204.6** | **3.0** | **6.1** | **8.4** |

***** Note: Account records variances between actual capital and non capital and firm capital commitment incurred for the DRP and the corresponding forecasts reflected in the revenue requirement approved by the OEB

[1] Total depreciation as shown in Ex. F4-1-1, Table 2, Note 1.

[2] Includes income tax impacts related to cost of capital and depreciation account additions. Does not reflect CCA variances, as CCA is claimed for all eligible DRP expenditures pursuant to an election under the *Income Tax Act (Canada)* noted in Ex. D2-2-1, p. 29, note 2. Interest on the outstanding account balance is also excluded.

Please provide a similar chart, updated to include the actual amounts included in rate base for DRP from 2012 to 2015 and the proposed amounts from 2016 to 2021.

## CAPITAL STRUCTURE AND COST OF CAPITAL

### Issue 3.1
### Are OPG's proposed capital structure and rate of return on equity appropriate?

### 3.1-Staff-10
<u>Ref: Exh C1-1-1, Chart 1</u>
Chart 1, from page 1 of Exh C1-1-1, is replicated below.

| Rate Base | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **Hydro ($B)[1]** | 7.5 | 7.5 | 7.5 | 7.6 | 7.7 |
| **Nuclear ($B)[2]** | 3.3 | 3.5 | 3.5 | 7.5 | 8.0 |
| **Total ($B)** | 10.8 | 11.0 | 10.9 | 15.1 | 15.6 |
| **Nuclear Proportion** | 31% | 32% | 32% | 50% | 51% |

1. Reflects OPG's 2016-2018 Business Plan, which includes a projection for 2019-2021 (Ex. A2-2-1 Attachment 1).
2. From Ex. I1-1-1, Table 1, sum of line 5, line 6 and line 7. Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital

structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

a) Please confirm whether the rate base values shown are: i) beginning of year; ii) mid-year or average of the year; or iii) end-of year.
b) OPG proposes that the equity thickness for the combined hydroelectric and nuclear generating regulated assets be increased to 49% for the whole period of the five-year term, in light of increased risk. The significant capital additions are mainly due to the Darlington Refurbishment Program, which significantly increases the relative percentage of OPG's regulated asset rate base related to nuclear generation. However, from Chart 1, significant additions to the nuclear rate base only begin to occur in 2020, when the nuclear rate base becomes approximately equal to the hydroelectric rate base, and exceeds it only in the last year of the plan 2021. For the first three years of the plan (2017-19), regulated hydroelectric rate base remains more than double the nuclear rate base.

   Please explain why OPG is proposing that the 49% equity thickness apply to all years in the five-year plan. On an assumption that there could be increased risk due to the increased risk from significant nuclear capital investments, why wouldn't the increased thickness only apply, if necessary, beginning in 2020 or 2021?

**3.1-Staff-11**

Ref: Exh C1-1-1 Attachment 1, page 36, Figure 6

Concentric's report, at page 36, finds that PNW (Pinnacle West) has slightly less than 20% nuclear, EE (El Paso) has 30% and OPG has 50%. Value Line reports EE's and PNW's nuclear generation as 47% and 27% of nameplate capacity, respectively. To assist with reconciling the generation data shown in Figure 6:

a) Please provide copies of nuclear industry data from the World Nuclear Association and other sources referenced in your analysis. What specific types of data were used to evaluate business risk associated with the regulated nuclear facilities?
b) Exactly how does Concentric define generation mix (e.g., nameplate capacity, operating capacity, etc.)?
c) Please confirm that the generation mix for OPG is measured as forecast for 2017-2021 and please provide the time periods for which the proxy companies' generation mix was determined.

**3.1-Staff-12**

Ref: Exh C1-1-1 Attachment 1, page 15

The evidence describes the potential impact of the proposed nuclear refurbishments on OPG's default risk and other key credit metrics.

a) Exh C1-1-1 Attachment 1, page 15 states that "[c]redit metrics are expected to be pressured by deferral of revenues to mix the post-nuclear facility refurbishment period". Please provide any analysis conducted by Concentric, including associated workpapers and models, to evaluate the impacts on credit metrics and/or changes to default risks.

b) Include all calculations/estimates of key financial ratios (such as FFO Interest Coverage, FFO to Total Debt, Debt to EBITDA) developed/analyzed by Concentric for OPG over the 2017-2021 period.

**3.1-Staff-13**
Ref: Exh C1-1-1 Attachment 1, page 18
OPG is transitioning to an incentive rate plan for hydroelectric generation.

Please provide any analysis performed or relied upon by Concentric in evaluating changes in regulatory risk exposure to OPG's hydroelectric facilities as a result of transitioning to the five-year incentive rate plan. If an analysis was conducted, please include associated workpapers.

**3.1-Staff-14**
Ref: Exh C1-1-1 Attachment 1, pages 30-41
Concentric's Comparative Analysis, includes an analysis to select the proxy group of companies, and the evaluation of risks discussed under "Risk Analysis".

a) Please provide electronic copies of Exhibits 1, 2 and 3 referenced in the "Selection of Proxy Companies" and "Risk Analysis" subsections of the report (Pages 30 & 35).
b) Please provide exhibits showing underlying data and calculations of Capital Expenditures for proxy companies illustrated in "Figure 8: Forecasted Capital Spending/ Net PP&E" of the report (Page 36).

**3.1-Staff-15**
Ref: Exh C1-1-1 Attachment 1, page 34, Figure 5 and page 62, Exhibit 1: Proxy Group Criteria
Concentric has selected a proxy group that it has used for its analysis. Figure 5 on page 34 and Exhibit 1 on page 62 summarize some of the characteristics.

a) For each firm listed in Figure 5, what percentage of the firm's generation assets are subject to regulation?
b) For each firm listed in Figure 5, please provide the following:
   i. Total generation capacity (MW)
   ii. Generation capacity (MW) devoted to the unregulated wholesale market.
c) Does Concentric consider regulated and wholesale electricity generation to have the same business risk? Please explain.

**3.1-Staff-16**
Ref: Exh C1-1-1 Attachment 1, page 38, Figure 8
Concentric has selected a proxy group for its analysis of the appropriate capital structure.

a) Does Concentric have data on the composition of NEE's (NextEra) capital spending? If yes, please provide this data.

b) Does Concentric have data on the capital spending of the listed companies during the last 2 to 4 years? If yes, please provide the data in electronic format.

**3.1-Staff-17**

Ref: Exh C1-1-1/Attachment 1, page 25 of 73

In its evidence, Concentric makes reference in footnote 46 to a methodology paper by Dominion Bond Rating Service (DBRS) as the source for its summary in Table 3.

a) Please file the DBRS study entitled: "Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," October 19, 2015.
b) Are there any other studies or reports conducted or commissioned by credit rating agencies regarding the criteria on the form of economic regulation that credit rating agencies use for assessing the credit rating of regulated firms that Concentric is aware of and used in its report? If so, please provide copies of all such reports.
c) If such reports in b) were used, please indicate how and where they were used by Concentric in its analysis. If they were not used, please indicate why not.

**3.1-Staff-18**

Ref: Exh C1-1-1/Attachment 1

In its evidence, Concentric asserts that OPG's risk will increase over the 2017-2021 plan term as it is moving from a regime whereby OPG's payment amounts were set through a two-year cost of service methodology to one where the rates will be set for a five-year period and through an incentive regulation regime for the regulated hydroelectric generation assets.

While OPG's payment amounts have been set in the previous three applications based on a two-year cost of service approach, in each instance, there was an additional "bridge" year between the applications where there was no resetting or adjustment to the payment amounts in that year. In effect, approved payment amounts were only changed every three years.

a) Please provide Concentric's views as to whether OPG's payment amounts have not been sufficient or have otherwise increased OPG's business risk due to OPG deciding to stay out for an additional year before applying for cost of service-based payments.
b) Please provide Concentric's views on the role of existing deferral and variance accounts to mitigate revenue and cost risks during the years that OPG has stayed out before reapplying for new cost of service-based payments.

**3.1-Staff-19**

Ref: Exh A1-3-2

Ref: Exh C1-1-1 Attachment 1 pages 3-4, 24-26

On page 8 of Exh A1-3-2, OPG states:

> With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is

> conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.

On page 3 of Exh C1-1-1 Attachment 1, Concentric states:

> Specifically, in Concentric's view, there is an anticipated change in risk related to OPG's hydroelectric facilities that is attributable to the transition from a two-year cost of service rate-setting term to a five-year incentive regulation ("IR") regime.

Concentric provides its analysis on regulatory risk, specifically related to adoption of incentive regulation, on pages 24-26 of Exh C1-1-1. Concentric points to an analysis by DBRS, and further states, on page 26:

> The incentive regulation plan will be proposed for a term of five years (2017-2021) and does not include a proposal to rebase costs in 2017. As a result, costs last approved by the OEB in 2014 will provide the basis for OPG's payment amounts through 2021. Under the proposed hydroelectric IR plan, OPG will be exposed to the risk that costs deviate from the price cap over the five-year rate period. In addition to the decoupling of revenues from costs, the hydroelectric IR plan will differ from OPG's traditional regulatory framework in that rates will be established for a five-year period, whereas, OPG's cost of service rates have traditionally been set for significantly shorter periods of time (two years or less).

Concentric concludes on page 26:

> Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

a) What quantitative evidence does Concentric have that incentive regulation, subject to periodic reviews to rebase (reset) rates and given the existence of deferral and variance accounts and other mechanisms to mitigate rate impacts or the need for reviews and off-ramps subject to the forms of incentive regulation adopted by the OEB for electricity and natural gas distribution sectors, has resulted in increased operational risk for electricity and gas distribution utilities compared to the forms of regulation that they were subject to? Has this risk changed as experience with incentive regulation has been gained by both the OEB and regulated utilities?
b) With respect to the first quote from page 26 of Concentric's evidence, can Concentric confirm that, since OPG became subject to economic regulation by the OEB, OPG's rate applications have been for 2-year test periods and that OPG has

remained on an additional year without any rate adjustments before refilling for its next two-year test period cost of service-based payments application.

c) What evidence does Concentric have that OPG has been exposed to "risk" of cost under-recovery due to staying out for an additional year before re-filing?
d) How has Concentric taken into account, both qualitatively and quantitatively, the ancillary aspects of OPG's proposed hydroelectric IRM plan, such as existing and proposed deferral and variance accounts, accessibility to incremental capital modules, reporting and off-ramp mechanisms, in assessing how OPG is exposed to material increased risk during the proposed 5-year hydroelectric plan?
e) Please provide Concentric's reasons supporting its views of increased and material cost recovery risk for OPG going into the five-year hydroelectric IRM plan, as stated on pages 3 and 26 of Concentric's evidence, in contrast to OPG's evidence on page 8 of Exh A1-3-2, quoted above, that its hydroelectric operations are in a steady-state situation given operationalization of the Niagara Tunnel consistent with a price cap for incentive regulation, and that OPG felt that the 4-GIRM (Price Cap IR) form was best suited for its current (expected) hydroelectric operations.

**3.1-Staff-20**

<u>Ref: Decision with Reasons EB-2010-0008, pages 116-118</u>
<u>Ref: *Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets (EB-2012-0340)*, issued March 18, 2013</u>
<u>Ref: Exh C1-1-1</u>
<u>Ref: Exh I1-1-1 and Attachment 1 Revenue Requirement Work Form</u>

In OPG's application for 2011-12 payments, the issue of technology-specific costs of capital (i.e., separate costs of capital for each of hydroelectric facilities and nuclear facilities, based on different risks for the two types of generation) was considered. While it has been generally accepted in all previous payment amount applications that nuclear generation is generally more risky than hydroelectric generation, OPG's cost of capital for regulated generation assets has been set in aggregate. In the Decision with Reasons EB-2010-0008, the OEB concluded that there was inadequate quantitative evidence to establish technology-specific costs of capital for each of hydroelectric and nuclear generation.[1] Thus in all payment order applications to date, OPG's cost of capital has been set on a common basis for all prescribed generation assets. The only real difference is that the cost of capital and the deemed capital structure for nuclear are set on the prescribed nuclear assets less the adjustment for the lesser of the unfunded nuclear liability or asset retirement obligations.

In the current application, there is a bifurcated approach for the rate setting for nuclear and regulated hydroelectric generation assets.

a) Please confirm that the cost of capital explicitly reflected in the going-in hydroelectric payments (i.e., before the application of the first price cap adjustment for 2017), even with the proposed adjustments, would reflect the cost of capital approved in EB-2013-0321. In the alternative, please explain.

[1] Decision with Reasons EB-2010-0008, March 10, 2011, pages 116-8.

b) The cost of capital that is implicitly reflected in the hydroelectric payments "rates" will change every year in accordance with the fact that the price cap adjustment, and specifically the inflation component reflects changes in input prices, which include inflation on labour, material and capital equipment prices and the cost of financing (i.e., cost of capital), as the OEB has explicitly concluded in past policy.[2] Please confirm OPG's understanding that changes in the cost of capital are reflected, implicitly, through the price cap adjustment, even if an explicit decomposition of what the changed cost of capital parameters is not easily demonstrated.
c) For the payments for the nuclear assets, OPG has proposed that the cost of capital be set for nuclear at the outset of the plan. The forecasted weighted average cost of long-term debt varies by year, while the return on equity (ROE) and short-term debt rates and the capital structure are fixed over the five year term. This is demonstrated on sheet 4 "OEB Adjustment Sheet" of the Revenue Requirement Work Form (RRWF). Further, OPG has proposed a variance account that would track the revenue requirement impact between the forecast ROE approved in the decision to this application (initially proposed at 9.19%) and the ROE as annually updated in accordance with the OEB's policy on the cost of capital[3] for 2018 to 2021. This explicitly means that that the cost of capital explicitly varies on an annual basis. Please confirm.

**3.1-Staff-21**

Ref: Exh C1-1-1 Attachment 1, pages 18-26

Pages 18-23 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments in which it concludes that OPG's operational, regulatory and political risk with respect to the nuclear generation assets increases, while acknowledging that there are some mitigating factors with respect to OPG's approach to project planning and management of the DRP and the provisions of O.Reg. 53/05 effective January 1, 2016.

Pages 24-26 of Exh C1-1-1 Attachment 1 provide Concentric's qualitative assessments of OPG's rate proposals. In particular, on the middle of page 26, Concentric describes the nuclear rate smoothing proposal and how the variance between revenues and revenue requirement will be tracked in the rate smoothing deferral account per O.Reg. 53/05.

Nonetheless, Concentric concludes on page 26:

> Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

---

[2] Further, for hydroelectric, any difference in the revenue requirement between the current 45% equity thickness and that determined by the OEB in its decision to this application, and which OPG has proposed to be 49%, would be tracked for later disposition.

[3] Currently *Report of the Board on the Cost of Capital for Ontario's Rate-regulated Utilities, (EB-2009-0084)*, December 11, 2009.

The discussions on pages 18-23 and on page 26 are fully qualitative in nature. With respect to the nuclear rate setting proposal, please indicate how Concentric has translated the qualitative points on these pages to conclude that, as a result, OPG is exposed to "material incremental risk" over the 2017-2021 plan period.

**Issue 3.2**
**Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?**

**3.2-Staff-22**
<u>Ref: Exh C1-1-2</u>
In Exh C1-1-2, OPG documents its cost of debt, and notes that it is adhering to the approach approved in the previous payment amount applications.

With respect to new or forecasted debt during the test period, OPG uses estimates from Global Insights for the Forecast 10-year Long [sic] Canada Bond Rate, and adds on the observed corporate spread. OPG notes that the spread at the end of December 2015 was 161 basis points. OPG provides the forecasted 10-year Canada Bond Rate by quarter for 2016 to 2021 in Table 1, and the forecasted long term debt rate in Table 2.

a) Please provide a copy of the Global Insights forecast for January 2016 upon which OPG is relying for its forecasts shown in Tables 1 and 2.
b) In Table 1, the forecasted rate is 3.32% for 2019 Q1 and for every quarter thereafter. Please indicate whether the Global Insights forecast is 3.32% for each quarter from 2016 Q1 to 2021 Q4, or whether OPG has just extrapolated the rate for 2016 Q1 to be the same for all subsequent quarters during the test period.
c) If OPG has more recent forecasts from Global Insights or from any other economic forecaster for 10-year Government of Canada Bond Yield rate, please file these updated forecasts.

**3.2-Staff-23**
<u>Ref: Exh C1-1-2</u>
<u>Ref: Consensus Forecasts (January 2009 to date)</u>
<u>Ref: Bank of Canada website – month-end 10 Government of Canada Bond Yields</u>
<u>Ref: O.Reg. 53/05</u>
OPG has relied on the methodology accepted by the OEB in its prior payments applications with respect to the methodology for forecasting the long-term debt rate for forecasted new long-term debt that it expects to incur during the test period.

OPG's methodology is similar to that adopted by the OEB for estimating the deemed long-term debt rate that applies or acts as a ceiling on long-term debt costs, in accordance with the OEB's current cost of capital policy as documented in the Report of the Board on the Cost of Capital for Ontario's regulated Utilities (EB-2009-0084), December 11, 2009. However, the methodology differs in two major respects:

- OPG forecasts the rate for new debt "based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks."[4]
- Since OPG's test period has been for two years in all previous payments applications, and the forecast period for the application is longer than the one-year horizon in *Consensus Forecasts* as used by the OEB, OPG uses longer-term estimates of the 10-year Government of Canada bond yield from IHS Global Insights to cover the 2-year test period.

OPG is not proposing any changes to its previously accepted methodology. However, with the longer term period of the current application from 2017-21, in addition to the bridge year of 2016, it is forecasting the cost of new or replacement debt over a forecast period of 6 years, at least double that from previous applications.

OEB staff undertook an analysis to compare the forecasting error of the three-month ahead and 12-month ahead forecasts of the 10-year Government of Canada bond yield as published by *Consensus Forecasts*, and which the OEB relies on for its long-term debt rate and ROE estimates. This analysis calculates the variance between the month-end 10-year Government of Canada bond yield as published on the Bank of Canada website against the 3-month and 12-month ahead forecasts for the 10-Year Government of Canada bond yield published earlier in Consensus Forecasts for that same month-end. OEB staff notes that IHS Global Insights is one of the economic forecasters surveyed by *Consensus Forecasts*, and so has done the analysis based on both the overall Consensus Forecast and on the IHS Global Insights estimates provided to and published by *Consensus Forecasts*. The analysis was done for all months from January 2010 to date, covering the period of the OEB's current cost of capital methodology and also since the recovery from the 2008-2009 global economic downturn and the current period of low interest rates.

The analysis is documented in a separate Microsoft Excel spreadsheet.

The results are summarized in the following table:

[4] Exh C1-1-2 page 3

**Variance from actual 10-year Government of Canada bond yield month end**

**January 2010 - July 2016**

| | *Consensus Forecasts* | | | IHS Global Insights estimate from *Consensus Forecasts* | |
|---|---|---|---|---|---|
| | Difference from actual of 3-month forecast | Difference from actual of 12-month ahead forecast | | Difference from actual of 3-month forecast | Difference from actual of 12-month ahead forecast |
| Mean | 0.30 | 0.90 | | 0.44 | 0.94 |
| Max | 1.21 | 2.21 | | 1.48 | 2.1 |
| Min | -0.73 | -0.63 | | -0.91 | -0.66 |

All numbers are percentages

The analysis demonstrates the forecasting errors. First, the forecasting error is generally higher for the 12-month ahead forecast than for the three-month ahead forecast, and the bias is much higher for the longer-term forecast. It would be expected that even longer forecasts – 2-, 3- or 5-years would show even larger forecasting errors.

These results are not surprising in current economic conditions, where persistent low interest rates make the likelihood and magnitude of under-forecasting less than for over-forecasting. Nor does this imply that the forecasts are not credible or should not be used, but that caution is advised. Longer-term forecasts are much more likely to be in error and to be significantly over-forecasted under current conditions.

OPG has proposed that its weighted average cost of long-term debt, applicable to $4,000M in new and replacement debt over the period 2016-2021 be approved in this proceeding. OEB staff also notes that the weighted average long-term debt rate approved is also used to calculate the carrying costs on the rate smoothing deferral account set out in O.Reg. 53/05.

a) Has OPG conducted any similar analysis of the forecasting error of the IHS Global Insights forecast data that it subscribes to? If so, please provide copies of any such analyses.
b) Can OPG undertake to provide an analysis similar to OEB staff's analysis based on IHS Global Insights. If not, please explain.
c) The analysis indicates that there is high risk of forecasting error in the long-term debt rate, and that this increases the farther out the forecasting is. As shown in Charts 1 and 2 of Exh C1-1-2, OPG is forecasting 6-years out. OPG has also proposed a new Nuclear ROE Variance Account to track the impact on the nuclear revenue requirement of the annual update of the ROE. How does OPG propose to mitigate the risk that the long term debt rate and/or that OPG's new or replacement long term debt does not occur as forecasted?, Would it not also be reasonable that an account be used to track the variance of the nuclear revenue requirement in each year from

what is approved in this application and what would be the revenue requirement based on actual debt and the actual weighted average cost of long term debt?

d) A variation on c) would be for OPG, in its annual payment application which it proposes to file to update the hydroelectric payments in accordance with the approved hydroelectric Price Cap plan, to also file updated forecasted long-term debt rates based on shorter-term forecasts (3-months and one-year ahead) of its expected debt cost. The forecasting error would be much smaller. The approach would be analogous to what Enbridge Gas Distribution Inc. does with its annual rate applications under its current multi-year rate plan.

   Please provide OPG's views as to whether the account described in c) or that in d) is preferable. Please explain.

**CAPITAL PROJECTS**

**Issue 4.1**
**Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?**

**4.1-Staff-24**
Ref: Exh A1-6-1 Attachment 1
O. Reg. 53/05 requires that the OEB ensure that OPG recovers costs to increase the output of, refurbish or add operating capacity to a generation facility if the costs were prudently incurred. In EB-2007-0905, OPG Payment Amounts April 1, 2008 to December 31, 2009, the OEB established the Capacity Refurbishment Variance Account (CRVA) to be used for this purpose.

Please identify which projects under OPG's Nuclear Operations capital forecast for 2016 to 2021 qualify for treatment under O. Reg. 53/05 and therefore for which the CRVA would be used.

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

**4.2-Staff-25**
Ref: Exh D2-1-3, Attachment 1, Tab 1
The referenced evidence is a request for approval of $9.7M (over the approved execution-full Business Case Summary (BCS)) for the Darlington Operations Support Building Refurbishment. The original project cost was forecasted to be $46.7M[5]. The Engineering, Procurement, Construction (EPC) contract is identified as being $14.4M over the original budget.

[5] EB-2013-0321, Exh. D2-2-1, Attachment 8-4

a) Please explain the root causes for the cost variance and what actions OPG has taken to better manage projects in future to prevent such over-variances.
b) What was the final project cost?
c) Please confirm whether the OPG Project Management cost for project oversight was $3.7M. If not, what was the final OPG Project Management cost?
d) Please summarize the role of OPG Project Management in project oversight for the Darlington Operation Support Building Refurbishment.
e) What is the typical cost as per cent and/or dollars for OPG Project Management?

**4.2-Staff-26**
Ref: Exh D2-1-3, Attachment 1, Tab 18
The BCS for the Darlington Restore Emergency Service Water and Fire Water Margins project estimates the project cost to be $20.9M higher than the previous estimate and cost is identified as a high risk.

a) Please provide a detailed explanation for the significant increase in estimated project cost.
b) Please provide an update on the status of this project with respect to cost and schedule including meeting the pre-requisite of installation completion prior to the start of Darlington Refurbishment in 2016.

**4.2-Staff-27**
Ref: Exh D2-1-3, Attachment 1, Tab 19
The BCS for the Darlington Station Roofs Replacement Project is a partial-release BCS for $0.8M approved in November 2012. The estimated total project cost including contingency is estimated to be $36.3M with a 2018 target project completion date. The BCS also identifies a preliminary design completion target date of September 9, 2013.

Please provide an update on the status of the project with respect to both schedule and cost and the reasons for variances, if any, and their impact.

**4.2-Staff-28**
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.

**4.2-Staff-29**
Ref: Exh D2-1-3, Attachment 1, Tab 21

The BCS for the Darlington Water Treatment Plant (WTP) Replacement Project is a partial-release BCS approved in October 2012 for $5.2M, intended to complete Phase 1, the Full Definition Phase (consisting of Preliminary and Detailed Design), of the project. The BCS estimates the total project cost including contingency at $57.8M with a target in-service date of November 25, 2016 for the new WTP.

a) Please provide an update on the status of the project with respect to both schedule and cost including any subsequent BCS(s) approved since October 2012.
b) Please advise if there are any implications on station operation if the stated target in-service date of November 25, 2016 is not met.
c) Please advise if OPG has made a decision yet whether or not to outsource the operation of the new WTP. If yes, does OPG project there to be any associated future Operating and Maintenance cost savings relative to those for the existing WTP? If yes, what are they?

**4.2-Staff-30**

Ref: Exh D2-1-3, Attachment 1, Tab 22

The BCS for the Darlington “Install Multi-Gas Analyzers on the Main Output Transformers (MOT), the System Service Transformers (SST) and the Unit Service Transformers (UST)” project identifies the project scope to include the installation of on-line Multi-Gas Analyzers on the station’s twelve MOT, four SST, and four UST.

a) In line with present industry standards and the World Association of Nuclear Operators, on-line Multi-Gas Analyzers are recommended on power transformers. Has OPG conducted any benchmarking comparisons or studies of similar multi-gas analyzer installations at other utilities? If yes, how does OPG’s project unit costs compare to these other installations?
b) The BCS indicates that the replacement of the High Voltage Bushing Monitoring (HVBM) was removed from the project scope, largely the result of an increase in the HVBM cost estimate from $4M to $7.2M. OPG intends instead to replace the HVBM during the Darlington Refurbishment outages. Why does OPG consider this to be a cost-effective decision and what are the estimated future costs of the HVBM replacement?
c) Will the cost for this work now be included as part of the DRP costs?

**4.2-Staff-31**

Ref: Exh D2-1-3, Attachment 1, Tab 23

The BCS for the Darlington Radiation Detection Equipment Obsolescence project is a partial-release BCS, approved in January 2014, for $1.15M and intended to complete the scope definition. The BCS estimates the total project cost at $46.875M including contingency and identifies a target date of October 30, 2015 for the preparation of the BCS for the next phase.

a) Has the scope definition work been completed as planned? Please provide an update on the status of the project with respect to cost and schedule.

b) It would appear that many, if not all, of the seven radiation detection and monitoring systems are critical to station and unit operation. Will the replacement of these systems require close integration with the Darlington Refurbishment Program? If yes, which of these systems are on the critical path as part of the Unit 2 refurbishment outage?

**4.2-Staff-32**

Ref: Exh D2-1-3, Attachment 1, Tab 24

The BCS for the Darlington Condenser Cooling Water and Low Pressure Service Water Travelling Screen Replacement project estimates the total project cost to be significantly higher, $37.6M including contingency, compared to the estimated total project cost of $24.4M identified in the previous partial-release BCS. While the BCS identifies the contributing factors for the $13.3M variance, the BCS also states that actuals from the first screen installations have been used to estimate future installation costs of all units.

a) Did OPG factor in the experience from these installations in arriving at new estimates, i.e. incorporated lessons learned to prevent recurrence, instead of just using the actual cost data?
b) Please explain the relatively high OPG Project Management costs (10% of the total project estimate) on this project.

**4.2-Staff-33**

Ref: Exh D2-1-3, Attachment 1, Tab 25

This BCS for the Darlington Shutdown Cooling Heat Exchanger (HX) Replacement project is a Phase 2 Partial Definition & Execution BCS and is subsequent to a previous Phase 1 Partial Definition BCS. The BCS states that a Phase 3 Full Execution BCS is planned in the future.

a) The BCS discusses a phased approach to awarding EPC contracts. Please explain whether the phased approach applies to the same vendor in each phase or whether each phase is open to multiple vendors:
    i. If the former, please clarify how project cost risks are mitigated unless the successful vendor has already committed to a preliminary cost for each contract phase;
    ii. If the latter, please clarify how this approach minimizes overall project costs including the management of resource risks.
b) The BCS states that estimated OPG resource costs have increased from $3.4M to $10.6M as a result of increased resource requirements resulting from a longer HX replacement duration. In particular, the BCS states that the previous HX replacement duration was based on a 2-week installation period working 24/7, and a 6-week installation period working 40 hours/week. The new HX replacement duration is based on 30-day installation period working 24/7, and a 6-week installation period working 40 hours/week. Please clarify how these changes result in the magnitude of the increased variance as stated.

**4.2-Staff-34**

Ref: Exh D2-1-3, Attachment 1, Tab 26

This BCS is with respect to the Darlington Neutron Overpower & Ion Chamber Amplifier Replacement (Reactor Regulating System, Shutdown System 1 & Shutdown System 2) project.

a) The BCS covers the replacement of In-Core Flux Detector (ICFD) and Ion-Chamber (IC) amplifiers only. Please confirm whether the neutron detectors and ion chambers will also need to be replaced or not. If yes, please explain when.
b) Please clarify why the purchase of off-the-shelf amplifiers is not a viable option given the widespread use of such equipment in the nuclear industry. Alternatively, was the option of replacing the existing ICFD and IC including the associated amplifiers with integral units considered?

**4.2-Staff-35**

Ref: Exh D2-1-3, Attachment 1, Tab 27

This BCS is for the Darlington Zebra Mussel Mitigation Improvements project and identifies a target project in-service date of July 25, 2016.

a) Please provide an update on the status of the project (cost and schedule) given the stated target in-service or completion date of July 25, 2016.
b) The BCS states that OPG has taken into account the Pickering experience with regards to the implementation of de-chlorination systems and their operations. To the extent that OPG's hydroelectric stations are also susceptible to zebra mussel fouling, has OPG also considered the hydroelectric experience in dealing with zebra mussel fouling in the Darlington project? If so, please explain.

**4.2-Staff-36**

Ref: Exh D2-1-3, Attachment 1, Tab 28

The BCS for the Darlington Highway 401 and Holt Road Interchange project relates to OPG's funding of a portion of the total project cost. The work is to be executed by the Ontario Ministry of Transportation.

a) Please provide an update on the status of the project (cost and schedule) given the stated target date of December 2015 for construction completion.
b) Is OPG liable for any future maintenance costs following the project completion?
c) The BCS states that in order to maximize the productivity at the refurbishment worksites, OPG would be negotiating with the trades unions to have the trades report for work at the jobsite, rather than at the entrance to the site. The outcome of these negotiations has significant impacts on productivity and therefore cost and schedule of the refurbishment project. What is the status of these negotiations and what are the associated impacts, if any?

**4.2-Staff-37**

Ref: Exh D2-1-3, Attachment 1, Tab 29

The BCS for the Darlington OH180 Programmable Logic Control Aging Management Hardware Installation project identifies a planned future partial-execution BCS release in March 2016.

a) What is the status of the partial-execution BCS targeted for approval by 31 March, 2016? If approved, please provide a copy.
b) Has a decision been made with respect to proceeding with either re-engineered Input and Output boards or their refurbishment? What are the associated implications, if any?
c) From a project schedule standpoint, are there any criticality issues relative to the Darlington Refurbishment outages? If yes, what are the associated impacts?

**4.2-Staff-38**

Ref: Exh D2-1-3, Attachment 1, Tab 30

This BCS is a partial-definition release for the Darlington Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management project intended for preliminary engineering and procurement of engineering services.

From a project schedule standpoint, are there any criticality issues relative to the Darlington Refurbishment outages? If yes, what are the associated impacts?

**4.2-Staff-39**

Ref: Exh D2-1-3, Attachment 1, Tab 31

This BCS for the Darlington Generator Stator Core Spare project covers the procurement of the spare generator core and discusses its application in the replacement of the Unit 3 and Unit 4 stator cores only.

a) Please clarify what the corresponding situation and associated risks are with the Units 1 and 2 stator cores and windings; as these do not seem to be covered by the current project.
b) How will their integrity be managed to provide continued service to the end-of-life of the refurbished Units 1 and 2?

**4.2-Staff-40**

Ref: Exh D2-1-3, Attachment 1, Tab 32

The BCS for the Darlington Vault Cooling Coil Replacement project states that the project is not currently in the Operations Business Plan and that it was originally planned for during the DRP outages. The BCS also states that while replacement of some vault cooling coils has been advanced, the remaining coils will be replaced during respective unit refurbishment outages.

Please clarify what project scope and costs will be included in Nuclear Operations and reclassified from the Refurbishment Program scope and what remains within the DRP envelope.

**4.2-Staff-41**

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?

**4.2-Staff-42**

Ref: Exh D2-1-3, Attachment 1, Tab 35

This BCS is for the Fukushima Phase II Beyond Design Basis Event Emergency Mitigation Equipment project. The total project capital ($46.3M) and Minor Fixed Assets (MFA) ($13.8M) costs attributed to Pickering (6 operating units) appear to be proportionally much higher than those attributed to Darlington ($28M capital and $2.1M MFA).

Please explain what the main factors are that contribute to these cost differences.

**4.2-Staff-43**

Ref: Exh D2-1-3, Attachment 1, Tab 36

This BCS is for the (Pickering) Machine Delivered Scrape project.

a) Please provide an update on the project status, particularly with respect to any information that OPG has with respect to the on-reactor deployment of the Circumferential Wet Scrape Tool by a non-OPG CANDU operator in 2015.
b) Based on this and any other information, please confirm whether OPG plans to continue with the project as discussed in the BCS and/or whether these plans have materially changed relative to the planned life-extension date of the Pickering B units to 2024.

**Issue 4.3**

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

**4.3-Staff-44**

Ref: Exh A1-3-3. Page 11

In the above reference, OPG has stated that "changes to public policy, especially the Government of Ontario's Long Term Energy Plan ("LTEP") could impact OPG's nuclear production. In particular, a change to the refurbishment schedule for future units at the Darlington generating station…"

a) What is OPG's understanding of when the Government of Ontario would make a decision about whether or not there could be a change to the refurbishment schedule and possibly the cancellation of the refurbishment of units subsequent to Unit 2?
b) What is OPG's understanding of what factors the Government would consider in making such a decision?
c) If the Government of Ontario were to cancel the DRP after Unit 2 is complete, what Facilities and Infrastructure assets would no longer be required?

**4.3-Staff-45**

Ref: Exh D2-2-1 Chart 1

In 2016, OPG began the execution phase of the $12.8B refurbishment of the Darlington Nuclear Generating Station. OPG has selected a "multi-prime contractor" model for DRP. OPG is the integrator among the prime contractors and is responsible for the entire DRP. OPG Functional Support refers to work including oversight, coordination and integration among the various contractors and ongoing station operations.

a) Is OPG asking for $12.8B to be approved by the OEB in this proceeding?
b) In Chart 1 of Exh D2-2-1, the functional support cost is presented with respect to the total DRP forecast cost of $12.8B. The functional support cost is forecast to be 17% of the total. In Figure 1 of the same exhibit, there is a breakdown of the forecast Unit 2 in-service amounts. The functional support cost is forecast to be 25% of the total. Why is the functional support cost as a percentage of total higher for Unit 2?
c) How do the forecast functional support costs compare with other mega-projects that have employed a multi-prime contractor model? If there is a significant difference, please explain why.

**4.3-Staff-46**

Ref: Exh D2-2-2, Figure 1

Ref: Exh D2-2-2, Attachment 2, Appendix B

The above references provide organizational charts for the Nuclear Refurbishment Organization Structure and DRP

For the key positions, please provide copies of the resumes for the individuals filling these positions, and summarize the individuals' experience with the multi-prime contractor model, nuclear refurbishments and managing outages of units.

**4.3-Staff-47**

Ref: Exh D2-2-2, page 7

The above reference explains that the Planning and Controls Function supports the DRP through the establishment and application of project controls, including cost management, reporting, and risk management at both the Program and project levels.

a) Describe how and when OPG will continue to assess risks of the DRP during the execution phase and provide a copy of all written processes and procedures.
b) What reporting system is set up for this? E.g. what data will be provided to management? What is the frequency of risk updates to management?
c) What efforts are being made to ensure that all of the materials/equipment/tools are procured, staged, and ready to be released to the project?

**4.3-Staff-48**

Ref: Exh D2-2-2

a) Provide a copy of all processes and procedures (which have not been provided elsewhere in the evidence) that OPG has put in place to manage the DRP. Include the date of adoption and revision(s). Provide all policies and procedures for the DRP including, but not limited to, OPG Governance, OPG's Project Management Standards, Project Oversight Standards.
b) Provide the written processes and procedures that govern how OPG will evaluate and report on the project schedule.
c) Provide the written processes and procedures that explain how OPG will integrate contractor schedule updates throughout the execution phase of the DRP.
d) Describe OPG's Change Management procedure and systems for tracking performance and monitoring contractor change orders including a copy of all applicable written processes and procedures. Identify the OPG Staff with responsibility for administering the change management procedure and explain decision making authority of the OPG project management team members involved in change management.
e) Describe OPG's plan to coordinate engineering changes during the execution of Unit 2 and through future units. Provide all applicable written processes and procedures.
f) What systems, processes, and procedures will OPG use to track each contractor's field performance and monitor contractor change orders? Provide a copy of all written processes and procedures.
g) Provide any written procedure regarding commercial correspondence and contractual notices that OPG will use for the DRP.
h) Provide the written cost control process, if any, for the DRP.
i) Who on the OPG project team is responsible for reviewing and vetting claims received from the Project's contractors?

**4.3-Staff-49**

Ref: Exh A2-1-1 Attachment 5, page 55

Ref: Exh D2-2-3, Attachment 6, RFR Contract, Article 16.2

Ref: Exh A1-6-1 Attachment 1, O. Reg 53/05, page 3

The first reference above provides the total commitments related to DRP, should OPG close the project, as $284M. The second reference details the payments due by OPG to the RFR contractor should the contract be terminated early by OPG. The third reference is the regulation directing the OEB to ensure that OPG recovers firm financial commitments incurred with respect to DRP, if OGP makes the financial commitments prudently.

a) Please provide details of what is included in the $284M from reference one.
b) Does the $284M include all the payments to all contractors that OPG would be responsible for upon termination, such as those outlined in the second reference above?

**4.3-Staff-50**

Ref: Exh D2-2-3, Chart 1

a) Describe all “off ramps” for each major work bundle. What is the governing process for OPG to determine whether to exercise the off-ramps? How will this decision be communicated to all interested parties? What are the cost categories that will be payable to the contractors upon execution of each of the off-ramps?
b) Describe what information OPG will gather, who will receive the information, when the information will be provided, and how the decision will be made whether to the exercise the off-ramp during or after the completion of Unit 2. Provide the same information for all of the other units and the process OPG will use to assess whether to exercise the off-ramps throughout the project.
c) Describe the governing process regarding the off-ramp for when a prime contractor is substantially below expectation. What does “substantially below expectation” mean? What information will this determination be based on? Who will have access to that information, when will it be provided, and who will make that decision?
d) What actions must the contractors take to recover in the event of a project schedule delay for which the contractor is responsible?

**4.3-Staff-51**

Ref: Exh D2-2-3, Chart 2

The above reference provides an overview of the Major Work Bundles for DRP. For those contracts that use a pricing model of a target price:

a) Please confirm that no overheads are included in the estimated costs, and
b) Please explain how OPG will ensure that no overheads are included in the actual costs.

**4.3-Staff-52**

Ref: Exh D2-2-4, page 3

The above reference indicates that OPG reviewed past CANDU and other nuclear refurbishments such as Point Lepreau refurbishment, OPG’s Pickering ‘A’ return to service and safe storage projects, Bruce Power’s Unit 1 and 2 refurbishments, and Korea Hydro & Nuclear Power’s Wolsong-1 refurbishment.

Please describe, in general terms, the similarities and differences between the DRP and these other refurbishment projects.

**4.3-Staff-53**

Ref: Exh D2-2-4, page 3

a) Please provide information the OPG team reviewed during the Planning Phase regarding the following projects: Point Lepreau Nuclear Generating Station, Bruce Nuclear Generating Station, Pickering Nuclear Generating Station, Wolsong Generating Station, Vogtle Electric Generating Plant, Watts Bar Nuclear Generating Station, London Olympics, and Heathrow International Airport.

**4.3-Staff-54**

Ref: Exh D2-2-4, Figure 1

The above reference shows the total definition phase expenditures to be $2.2B.

a) Please provide a variance of the actual amount of $2.2B to the budgeted amount for the definition phase.
b) Please provide the amount of the $2.2B that is attributable to Unit 2 versus supporting the entire four unit DRP.
c) Please provide details, i.e. projects and amounts, of the e $2.2B that has been put in-service to the end of 2015.

**4.3-Staff-55**

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

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

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

**4.3-Staff-56**

Ref: Exh D2-2-8, Chart 2

The above reference states that the overall Release Quality Estimate (RQE) is a Class 3 and provides the individual class estimate levels for the major work bundles. The RQE is dated November 13, 2015.

Have any of the major work bundle estimates been revised to a higher class estimate since release of the RQE? If so, please provide details.

**4.3-Staff-57**

Ref: Exh D2-2-8, Attachment 1

OPG has provided a Release Quality Estimate (RQE) as part of the DRP Execution Phase Business Case Summary.

a) How will OPG determine whether it is necessary to reforecast the RQE? Provide all written processes and procedures regarding cost reforecast process.

b) How will OPG track cost trends and contingency? Provide all written processes and procedures.
c) What reporting tools for earned value, budget status, safety and project status will OPG use? What is the format and content for these reports? Who is responsible for generating these reports? Who will receive these reports and with what frequency?
d) For each Unit, identify what is the value and percentage of contingency applied to each major work bundle.
e) What is management contingency above the project contingency – how is it distributed across the projects?

**4.3-Staff-58**

Ref: Exh D2-2-6 and D2-2-8

a) What is the process that OPG will use to make DRP decisions impacting cost and schedule?
b) Who within the project management organization has what type and level of decision-making authority?
c) Describe OPG's strategy to work through disagreements with contractors that have cost and schedule impact, i.e. explain how these issues will be identified, escalated and resolved? What data will be provided to the person(s) with decision making authority? What is the timeline for this process?

**4.3-Staff-59**

Ref: Exh D2-2-8, Attachment 2, page 24

The above referenced Modus report states that "The various islanding projects are relatively small in cost but significant to the DR Project's success. The design of the Darlington plant, in particular the fueling bay that runs below the reactors, makes isolating a single unit for refurbishment a challenge."

a) Please confirm that the isolating of a single unit from the operating units is unique to the DRP (i.e. that it has not been done on prior nuclear refurbishments).
b) What special precautions have been taken to ensure that the operation of the remaining units does not interfere with the refurbishment of Unit 2 and vice-versa?
c) How much has been spent to date on the islanding project compared to budget?
d) What contingency has been provided for the various islanding projects?

**4.3-Staff-60**

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

The above referenced Release Strategy shows work on Unit 3 starting immediately after Unit 2 returns to service.

Please explain how this schedule will enable OPG to internalize and apply the lessons learned from Unit 2 going forward.

**4.3-Staff-61**

Ref: Exh D2-2-3, Attachment 1, page 6

For the DRP Execution Phase, calculation and payment of all cost incentives and disincentives will be done on an aggregate basis for all completed units.

a) Please explain how this will work in practical terms with the CRVA for DRP. For example, will the CRVA only be cleared at the completion of all four units?
b) Were any incentive or disincentive payments made during the definition phase?

**4.3-Staff-62**

Reference: D2-2-8, page 8

The above reference states that OPG will complete the Unit 2 refurbishments within the total budget envelope of $4.8B.

a) How does that fit in with the Capital Refurbishment Variance Account (CRVA)? I.e. if Unit 2 in service additions are greater than $4.8B, will those costs go into the CRVA?
b) When OPG comes in for its next application for 2022 will there be a reforecast of the remaining DRP costs?

**4.3-Staff-63**

Ref: Exh A1-2-2

Ref: Exh D2-2-8, Attachment 1

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

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

**4.3-Staff-64**

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

The above reference states that OPG's current Levelized Unit Energy Cost (LUEC) estimate of 8.1 ¢/kWh (2015$) for the DRP is within the previously communicated estimate of 8 ¢/kWh in 2009$.

a) What total cost can the DRP rise to in 2026$ that would still be equivalent to the LUEC 2009 at less than 8 ¢/kWh?
b) Please calculate the LUEC when the full $12.8B is used.
c) Please calculate the LUEC when the costs related to previous DRP projects that have been moved to Nuclear Operations is added back.

**4.3-Staff-65**

Ref: Exh D2-2-8 Attachment 1, page 28

OPG indicates that benchmarking has been done against other CANDU refurbishment projects at Point Lepreau and the Bruce 1& 2 Units. Please provide details.

**4.3-Staff-66**
Ref: Exh D2-2-8, Attachment 1 page 31
The above reference states that $503M of the $1.7B contingency is for schedule extension.

What is the worst case scenario (i.e. how many months past the current 112 months schedule) that this dollar amount of contingency will cover? For instance, would it cover a six month increase in duration of the overall schedule? If so, explain why the LUEC would increase by 0.1 cent/kWh with a 6 month increase in schedule.

**4.3-Staff-67**
Ref: Exh: D2-2-8, Attachment 1, page 31
$50M contingency is provided to retain critical trades and leadership resources between work on units. There are a number of other projects which are identified as possible other work.

a) How did OPG determine the $50M contingency amount? Please provide assumptions and references for any calculations.
b) If work on other projects does not proceed, how does OPG intend to use the $50M?
c) Does OPG forecast spending any of the $50M contingency in the 2017-2021 period?

**4.3-Staff-68**
Ref: Exh D2-2-8, Attachments 2, 3 and 4
In Attachment 2, BMcD/Modus made recommendations associated with certain components of the Release Quality Estimate (RQE). Similarly, in Attachment 3 KPMG identified a number of gaps and risks. In Attachment 4 the Expert Panel made eight recommendations.

a) Please provide a status update on OPG’s work in addressing BMCD/Modus’ recommendations.
b) Please describe how OPG is addressing the gaps and risks identified by KPMG.
c) Please provide a status update on OPG’s work in addressing the Expert Panel’s recommendations. Specifically, what adjustments were made to the project schedule, productivity expectations and project management plans subsequent to the receipt of the Expert Panel’s report.
d) On page 14 of Attachment 4, it states “it will take vigilant project management and worker productivity not generally experienced on retube projects in Canada to achieve a schedule equivalent to or shorter than the P50 schedule”. Please describe how OPG has determined that its worker productivity expectations are reasonable.

**4.3-Staff-69**
Ref: Exh D2-2-9, page 7

The above reference refers to the use of Earned Value Management as the primary method for DRP cost management and monitoring.

a) How will OPG monitor and track earned value for all contractors? Provide all written governing process and procedures and a narrative explanation including an example of how OPG will calculate SPI and CPI.
b) How is OPG going to track the Project's schedule and the progress of contractors pursuant to the schedule? Provide all applicable written policies and procedures.
c) How often are the contractors providing a schedule update to OPG?
d) Describe OPG's process for managing or releasing float. Provide the written governance process, if any.
e) Describe OPG's process for re-baselining the schedule, if necessary. Provide the written process and procedure, if any.
f) Explain the float built into the overall project schedule and how it is allocated for each Unit.

**4.3-Staff-70**

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.

**4.3-Staff-71**

Ref: Exh D2-2-10, Chart 1

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

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

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

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

**4.3-Staff-72**

<u>Ref: Exhs D2-2-7, D2-2-8 and D2-2-10</u>

OPG has provided copies of third party reports in the above referenced exhibits.

a) Please provide a copy of any other third party reports regarding the DRP prepared during the planning phase that have not already been filed by OPG in EB-2016-0152.
b) Please provide a copy of all audit reports regarding the DRP.
c) Will OPG receive reports from any other third party independent oversight groups involved in the DRP during the execution phase? What is the frequency? Will they generate written reports? Who will receive the reports?
d) What is OPG's Audit program during the execution phase of the DRP? What areas will be audited? What is the schedule for the audits during the execution phase of the DRP? Who will receive the reports?

**4.3-Staff-73**

<u>Ref: Exh D2-2-11, Attachment 3</u>

In her report, Dr. Galloway refers to numerous documents that she reviewed but which are not included as part of the application evidence. Therefore, please provide copies of the following, which are referred to on the indicated page of the reference:

a) Integrated Reporting Plan (pages 10 and 68)
b) Project Oversight Standard (pages 36 and 42)
c) Project Management Standard (page 42)
d) Records of Interviews (numerous references)
e) Program specific policies and procedures (page 43)
f) Planning and Controls Program Management Plan (page 56)
g) Risk Register (page 63)
h) Nuclear Projects Risk Management manual (page 65)
i) Readiness to Execute Plan (page 71)

**4.3-Staff-74**

<u>Ref: Exh D2-2-11, Attachment 3, page 10</u>

In her report, Dr. Galloway states that "[t]he Facilities and Infrastructure Projects (F&IP) and Safety Improvement Opportunities (SIO) were not necessarily completed per the initial planned schedule and estimate, however I did not find any fundamental issues that would impact the Program execution."

Please explain why OPG has such a high level of confidence in the forecasted schedule and budget for the remaining work in DRP when OPG was unable to complete the required preliminary work on budget and on schedule?

**4.3-Staff-75**
Ref: Exh D2-2-11, Attachment 3, page 53
Ref: Exh D2-1-3, Attachment 25, page 23
Ref: Exh D2-2-8, Attachment 1, page 7
Dr. Galloway in the first reference above, states that she found the Release Quality Estimate to be a Class 3, which according to the second reference above means that there is an expected accuracy range of -20% to +30%. The third reference states that OPG has determined the amount of contingency required to deliver the project, and produced a high confidence (P90) schedule.

Please reconcile a Class 3 estimate with P90, a 90% confidence that the contingency is appropriate and the schedule will be met.

**Issue 4.4**
**Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?**

**4.4-Staff-76**
Ref: Exh D2-1-3, Table 4
Please complete the following table with the requested information for Nuclear Operations in-service additions:

| Tier 2 and 1 projects | 2015 approved | 2015 actual | 2016 budget | Variance 2016 budget to 2105 actual |
|---|---|---|---|---|
| Project 1 | | | | |
| Project 2 | | | | |
| Etc. | | | | |
| Total for all other projects | | | | |
| Total | $120M+$66M = $186M | $181.8M | $466M | $284.4M |

Note: $66M is for the Operations Support Building and Auxiliary Heating System which were moved from DRP.

**4.4-Staff-77**
Ref: D2-1-3

For all Tier 1 projects for years 2014 and 2015, please provide the original approved project cost (as approved by the AISC), the actual cost, the projected in-service date provided and the actual in-service date.

**Issue 4.5**
**Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?**

**4.5-Staff-78**
<u>Ref: Exh: D2-2-10, page 16</u>
The above reference states that the Heavy Water Facility was originally budgeted at $110M but the updated budget is now $381.1M. OPG states that the original EPC contractor's design was not adequate and the contractor has been replaced.

a) Please provide details of any recourse OPG was able to take due to the inadequacy of the contractor's work.
b) The over variance is 247%. What lessons learned have been applied to the work on the DRP?

**4.5-Staff-79**
<u>Ref: Exh D2-2-10, page 20</u>
Variances in the total cost of the Water & Sewer project (+6.9M) and the Upgrade to the Electrical System (+$3.9M) were both attributed in part to issues which appear to have been unforeseen, e.g. the soil conditions for the Water & Sewer project or the legacy equipment grounding for the Electrical Power Distribution Project.

a) Were these risks identified at the beginning of the projects? If so, was any mitigation put in place? If not, why not?
b) What has OPG done to eliminate these types of risk going forward with DRP projects?

**PRODUCTION FORECASTS**

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

**5.1-Staff-80**
<u>Ref: Exh E2-1-1 page 2</u>
OPG states that its outage forecasts are based "on actual experience with similar work performed in the past at OPG and other organizations."

a) From which other organizations has OPG sought experience? How have these experiences impacted the forecast outage lengths in this application?
b) Has OPG sought experience from similar work performed at Ontario facilities operated by Bruce Power? If not, why not? Is so, please explain what was learned

and provide examples of how it has impacted any of the forecast outages in this application.

**5.1-Staff-81**

Ref: Exh E2-1-1 pages 4 and 8

For its Darlington facilities, OPG has forecasted a Forced Loss Rate (FLR) of 1% for 2016 through 2019, 4.2% for 2020 and 3.0% for 2021. OPG states that the increase to the FLR in 2020 and 2021 "reflects the return to service of Darlington Unit 2 from its refurbishment outage and is consistent with industry operating experience." Chart 3 shows an overall average FLR of 2.9% for Darlington facilities over the 2010-2015 period.

On page 8, OPG states that its forecast FLR of 1% "is aggressive" but "achievable based on expectations that OPG executes ongoing initiatives to improve equipment reliability that will stabilize Darlington's FLR."

a) What experience forms the basis for OPG's forecast increase to the FLR in 2020 and 2021?
b) Please reconcile the expectation that OPG's ongoing initiatives will "improve equipment reliability that will stabilize Darlington's FLR" with the forecast increase to the FLR in 2020 and 2021.
c) Given the history of under-production shown in chart 2 of Exh. E2-1-1 (line 3 Actual vs line 1 OPG Application), why is OPG proposing an "aggressive" FLR?
d) Please confirm that the planned "warranty" outages in 2020 and 2021 for unit 2 are not included in the forecast FLR for unit 2.
e) The unit 2 FLR is forecast to be 12 percent in the year of return to service and the year immediately following. Is OPG expecting unit 2 to be offline an additional 44 days (12 per cent of 365) in 2020 and 2021?

**5.1-Staff-82**

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?

**5.1-Staff-83**

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.

**5.1-Staff-84**

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?

**5.1-Staff-85**

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)?

**5.1-Staff-86**

Ref: Exh A1-4-3

OPG notes that it is currently planning to extend the safe operation of its Pickering nuclear units beyond 2020.

Please provide a production forecast for OPG's Pickering station reflecting the scenario in which OPG does not receive the necessary regulatory approvals to extend the operation of its Pickering station.

**5.1-Staff-87**

Ref: Exh E2-1-1-page 2 and 8

OPG notes in its application that it is following previous OEB decisions with respect to the production forecast. OPG specifically cites the OEB's observation that there is no need for an adjustment to production from "unforeseen major events" as a result of OPG's basing its production forecast on actual experience with maintenance performed in the past at OPG and other organizations.

a) OPG's proposal states that "the planned outage durations include a station level allowance for uncertainty related to potential discovery work. They also include a nuclear fleet level allowance to address risks to the completion of the outage on schedule, risks that could emerge from fleet aging issues, or from complexity in fleet level activities (e.g., availability of Inspection Maintenance Service resources to service multiple outages)."
    i. Is this uncertainty component for outages expressed as a separate input in the planning process?

   ii. How is this uncertainty component included in the outage schedule - is it a percentage of total outage schedule or an estimate of hours or days of uncertainty as determined from previous experience with similar activities?

b) Can OPG provide further elaboration on how it determines this uncertainty component and explain how it is materially different from an allowance for "unforeseen major events"?
c) When in 2021 is the six unit Pickering VBO scheduled to commence? Is there any flexibility in this schedule or is it governed by the CNSC?

**5.1-Staff-88**
<u>Ref: Exh E2-1-1-1 page 3</u>
In the Glossary of Outage and Generation Performance Terms OPG provides an explanation of planned outages and the procedures for scheduling outages with the IESO.

a) OPG states that it submits its planned nuclear outage schedule to the IESO early to secure an early time-stamp date.
   i. Typically, how "early" is early, noting that 28 days prior to the requested start date is the minimum?
   ii. Does the type and/or duration of outage contemplated determine how far in advance the request is submitted?
   iii. Has OPG submitted any requests for outages that are included in this production forecast?
b) According to the proposal a planned outage duration cannot be revised (increased or decreased) after the planned outage has commenced. This implies that at any time prior to the outage commencing, OPG can revise the duration of the specific outage. Is this correct?
   i. In OPG's experience has there ever been an instance of an outage duration being overestimated, resulting in an avoidable loss of production?
   ii. In OPG's experience has there ever been an instance of outage duration being underestimated, requiring a declaration of a "forced extension to planned outage(s)" (FEPO)?
c) What are the financial and revenue implications to OPG of either over- or underestimating planned outages in submitting its outage schedule to the IESO?
d) Is there an advantage to underestimating outage durations to avoid the certainty of lost revenues in case of an overestimate?

**OPERATING COSTS**

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

**6.1-Staff-89**
<u>Ref: Exh F2-2-1 page 1 and Table 1</u>

The evidence states that, “Base OM&A provides the main source of funding for operating and maintaining the nuclear stations in support of: the ongoing production of electricity from the operating nuclear units; ensuring the safe operation of the plants; improving the reliability of the nuclear assets, and ensuring compliance with applicable legislation and nuclear regulatory requirements.”

Table 1 sets out base OM&A by stations and by support. The 2015 actual base OM&A for the Darlington station was $298.9M. The average base OM&A for Darlington for the 2017-2021 test period is $314.92M. Please explain why the base OM&A for Darlington in the test period, when there are three operational units (and only two in 2021), is higher than the 2015 actual base OM&A when there were four operational units.

**6.1-Staff-90**

Ref: Exh F2-1-1 Attachment 1 page 4 and Table 1

At page 4, it states that Decommissioning and Nuclear Waste Management is accountable for the safe and cost effective shutdown and safe storage of Pickering and the strategic aspect of Pickering end of commercial operations.

Is the Decommissioning & Nuclear Waste Management budget for the test period at line 12 of Table 1 reflective of Pickering 2020 shutdown or Pickering 2022/2024 shutdown?

**6.1-Staff-91**

Ref: Exh F2-2-1 page 2

Ref: Exh F2-1-1 page 21

a) Nuclear base OM&A includes an inventory obsolescence provision. Please provide the reasons for inventory obsolescence and the cost in each year of the historical and forecast period.
b) When was the inventory reduction initiative introduced?
c) OPG states that “An Inventory Management Organization will be established for each [nuclear] station.” Will that organization be staffed with existing staff? If not, how many new FTE are forecast and what is the forecast cost?

**6.1-Staff-92**

Ref: Exh F2-3-3 Attachment 1 Tab 2

Ref: EB-2010-0008 Exh L-6.3-Staff-52

This BCS relates to the Fuel Channel Life Management (FCLM) Project (OM&A - Project # 10-62444) and the Annulus Spacer Retrieval Tool (ASRT) Project (Capital - Project # 28-66567). The BCS identifies a close-out date of June 2015 for the FCLM project and December 2012 for the ASRT project. The total FCLM project cost in the first partial-release BCS dated 2009-08-10 was estimated to be $24.92M.

Appendix B (Comparison of Total Project Estimates) on page 19 of the BCS estimates the total FCLM project cost now at $54.05M. A Project Variance Analysis is provided on page 20 of the BCS. In its response to OEB Staff Interrogatory #052 submitted as part of EB-2010-0008, OPG explained the basis of the cost sharing ratio of 5.5:3.5 (OPG:Bruce Power) for the FCLM project.

a) Assuming close-out of the project by June 2015, what was the final total project cost?
b) What was OPG's share of the total project cost and was it consistent with the cost sharing ratio of 5.5:3.5 between OPG and Bruce Power? If not, please explain why not.

**6.1-Staff-93**

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?

**6.1-Staff-94**

Ref: Exh F2-2-3 Attachment 2

This document contains a Technical and Economic Assessment of Pickering Extended Operations beyond 2020 and includes a partial release of $52M to cover incremental work program costs in 2016 and 2017. This includes the costs for the Fuel Channel Life Assurance Project, estimated to cost a total of $9M (refer to Table A1 on page 18 of Attachment 2).

Please advise if the Fuel Channel Life Assurance Project is subject to some sort of cost sharing agreement with another CANDU operator as was the case on both the Fuel Channel Life Management Project (Project # 10-62444) and the Fuel Channel Life Extension Project (Project # 10-80014).

**6.1-Staff-95**

Ref: Exh H1-1-1 page 24

The Nuclear Development Variance Account records variances between actual non-capital costs for planning and preparation for the development of proposed new nuclear generation facilities and the forecast costs in revenue requirement. In the previous proceeding, EB-2013-0321, OPG proposed that 2014-2015 OM&A expenditures for new nuclear development be entered in the variance account, i.e. the 2014-2015 forecast was $0.

What is OPG's proposal in the current proceeding? What is the forecast amount for each year of the test period?

**6.1-Staff-96**

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.

**6.1-Staff-97**

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?

**6.1-Staff-98**

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.

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

**6.2-Staff-99**
Ref: Exh A2-2-1 Attachment 1
Ref: Exh A1-3-2 page 36
OPG's 2016-2018 Business Plan has been filed as an attachment to Exh A2-2-1. Appendix 5 of the OPG 2016-2018 Business Plan summarizes Nuclear Financial Plan, Operational Targets and Initiatives. At Exh A1-3-2, it states, "OPG's nuclear business plan currently includes initiatives intended to improve reliability, human performance, and value-for money."

Please file the nuclear business plan.

**6.2-Staff-100**
Ref: Exh A2-2-1 Attachment 1
At page 30 of the attachment, a summary of operational targets for the nuclear business is provided. Please explain the unusually high collective radiation exposure target for Darlington in 2017, and the increasing exposure trend for Pickering in the 2016-2018 business plan period.

**6.2-Staff-101**
Ref: Exh F2-1-1 page 3 and 16
At page 16 of the reference, it states:

> The TGC/MWh for Darlington has been calculated on a normalized and non-normalized basis for 2017 and 2018 to account for the impact of reduced unit output during Darlington Refurbishment. The denominator in TGC/MWh, i.e., MWh, declines because units are being refurbished but there is not a corresponding decline in the numerator, as corporate allocated costs and station costs are largely fixed. The net impact will be to temporarily skew these metrics higher than would otherwise be the case. Nuclear Operations has set internal performance targets for TGC/MWh on a non-normalized basis, but for benchmarking against industry peers, will continue to compare Darlington's performance using a normalized TGC metric.

a) Please provide the Nuclear Operations internal performance targets for TGC/MWh, on a non-normalized basis or note whether the internal targets are provided in the nuclear business plan filed in response to a previous interrogatory.
b) Please provide the details of the normalized TGC calculation.
c) Is normalizing TGC standard practice for utilities during major nuclear refurbishments?
d) In 2015, ScottMadden validated the ongoing appropriateness of OPG's application of the benchmarking methodology. Was ScottMadden consulted about normalizing TGC during the DRP, and if yes, what was their feedback?

**6.2-Staff-102**

Ref: Exh F2-1-1 page 10

OPG benchmarks value for money performance on a $/generating unit basis, which OPG states eliminates generation impacts due to extensive outage programs, reactor design and unit size. Was ScottMadden consulted in 2015 about this value for money metric, and if yes, what was their feedback?

**6.2-Staff-103**

Ref: Exh A2-2-1 Attachment 1 page 30

The nuclear business operational performance and targets are summarized in a table at page 30 of the OPG 2016-2018 business plan.

a) Are the 2015 actual operational performance data annual results or rolling actual results? If the data are annual results, please provide the rolling results.
b) Note 1 to the table states that the Darlington targets reflect the impact of the Unit 2 refurbishment. Please identify the Darlington targets and explain how the Unit 2 refurbishment is reflected in these targets.

**6.2-Staff-104**

Ref: Exh F2-1-1 page 15 Attachment 1 pages 89 and 95

Ref: Exh F2-1-1 Table 1

The operator level summary at page 89 presents EUCG indicator results including TGC/MWh. The value for money definitions, including operating costs are provided on page 95. The footnote to Chart 4 at page 15 states that TGC/MWh excludes the centrally held pension and OPEB costs and asset service fees to align with industry standard.

Are all the costs listed in Table 1, Operating Costs Summary – Nuclear, of Exh F2-1-1 included in the determination of TGC/MWh except centrally held pension and OPEB costs and asset service fees ? If not, please identify which other costs are excluded and explain why they are excluded.

**6.2-Staff-105**

Ref: Exh F2-1-1 Attachment 3 page 13

Ref: EB-2010-0008 Exh F5-1-2

As part of its 2015 review, ScottMadden reviewed the use of benchmarks in the business planning process and target setting. Was there any review of OPG performance against the 2014 targets that ScottMadden proposed in 2009 and what were the results of that review? If not, why not?

**6.2-Staff-106**

Ref: Exh F2-1-1 Attachment 3 page 12

ScottMadden states that, "The work management metrics (Scope Stability and Schedule Adherence) are relatively new for the industry. OPG benchmarks their performance against these metrics at a lower level in the organization ..."

Please provide the scope stability and schedule adherence benchmarked data for 2014 and any prior years for which the data are available.

**6.2-Staff-107**

Ref: Exh F2-1-1 page 8, Attachment 1 page 57

Ref: EB-2013-0321 Exh F2-1-1 page 5

One of the reliability metrics is the "1 Year On-line Corrective Maintenance Backlog". The 2014 actual result for Pickering was 160 work orders per unit, while the 2014 benchmark median was 20. The 2011 actual result for Pickering as noted in the EB-2013-0321 application was also 160 work order per unit, while the 2011 benchmark median was 52.

At page 57 of Attachment 1, it states that Pickering has teams focused on reducing corrective and deficient work backlogs. Please explain why Pickering's performance on 1 Year On-line Corrective Maintenance Backlog did not improve in the 3 year period 2011 to 2014.

**6.2-Staff-108**

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

Attachment 2 is the "2014 Nuclear Staffing Benchmarking Analysis" prepared by Goodnight Consulting. The report is dated December 22, 2014. At page 3 of the report, there is reference to data as at March 2014.

a) Are the data and the analysis in this report reflective of benchmarking at March 2014?
b) Is this report reflective of data provided by OPG as undertaking J6.1 in the previous cost of service proceeding EB-2013-0321?

**6.2-Staff-109**

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.

**6.2-Staff-110**
<u>Ref: Exh F2-1-1 Attachment 2 page 13 and 28</u>
<u>Ref: EB-2010-0008 Undertaking J5.3</u>
<u>Ref: Exh F2-1-1 Attachment 4 page 12</u>
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

**Issue 6.3**
**Is the forecast of nuclear fuel costs appropriate?**

**6.3-Staff-111**
Ref: Exh F2-5-1
At page 3 of the evidence, it states that:

> Offsetting lower generation is the one time impact of a requirement for a load of new fuel to be included in the reactor core of Unit 2 prior to start-up. One-half of the cost of the new fuel load will be capitalized in 2019 when the new fuel is loaded into the reactor and after the refurbished unit is declared in service in 2020, depreciated over the station's remaining life. This is consistent with the concept that half of the fuel in the fuel channels will be unused at the end of the station life. The other half of the cost of the new fuel load for Unit 2 will be expensed in 2020 when Unit 2 is declared in- service.

a) What is the new fuel load cost that OPG proposes to capitalize and what is the new fuel load cost that OPG proposes to expense?
b) OPG proposes to depreciate a portion of the new fuel load over the station's remaining life, stating that "half of the fuel in the fuel channels will be unused at the end of the station life." Please explain this statement given the on-line refuelling capability of CANDU reactors.
c) Please explain OPG's past practice with respect to new fuel loads along with accounting rationale behind why the cost of the new fuel load is eligible to be capitalized.

**6.3-Staff-112**
Ref: Exh F2-5-1 page 6
Ref: Exh B1-1-1 page 6
On page 6 of Exh F2-5-1, it states that OPG will achieve the uranium concentrate inventory target of 288,000 KgU by 2019. The target was recommended by external consultants, Longenecker & Assoc., and noted in an April 2012 report filed in the previous proceeding, EB-2013-0321.

Does the inventory target reflect both Darlington refurbishment and Pickering Extended Operations?

**Issue 6.4**
**Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?**

**6.4-Staff-113**
Ref: Exh F2-7-1, pages 1 and 2

| | 2013 Budget | 2013 Actual | 2014 Approved | 2014 Actual | 2015 Approved | 2015 Actual | 2016 Budget | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DRP | 10 | 4.6 | 4.3 | 4.3 | 9 | 1.4 | 1 | 41.5 | 13.8 | 3.5 | 48.4 | 19.7 |
| F&IP | 8.2 | 1.7 | 2.3 | 2 | 9.3 | 0.1 | 0.3 | 0 | 0 | 0 | 0 | 0 |
| Total | 18.2 | 6.3 | 6.6 | 6.3 | 18.2 | 1.6 | 1.3 | 41.5 | 13.8 | 3.5 | 48.4 | 19.7 |

The above table shows the approved and actual OM&A for DRP for 2014 and 2015 and the forecasted OM&A for 2016 to 2021.

a) Given the capitalization criteria at Exh D4-1-1, please explain why these costs are not capitalized
b) OPG explains the variance between the 2015 approved and actual as primarily due to reclassification of expenses to Nuclear Operations. Was the DRP budget adjusted for these reclassifications?
c) OPG states that in 2017, $24.7M is related to Retube and Feeder Replacements for Unit 2 and in 2020, $30.3 M is related to Retube and Feeder Replacements for Unit 3. Please explain why the OM&A costs for Unit 3 are greater than Unit 2.

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

**6.5-Staff-114**
<u>Ref: Decision EB-2013-0321, page 51</u>
In approving the expenditures for Pickering Continued Operations (PCO), the OEB in its Decision in EB-2013-0321, relied on three factors. These were: (i) The extension of the Pickering units was consistent with Government direction and consistent with the Long-Term Energy Plan; (ii) benefits from Pickering Continued Operations were confirmed by the OPA; and, (iii) Pickering Continued Operations proposal was reviewed by the CNSC resulting in the renewal of Pickering's power reactor operators licence.

a) In OPG's view does Ontario's current (2013) Long-Term Energy Plan, endorse the continued operation of Pickering beyond 2020?
b) In OPG's view is the proposal to operate Pickering beyond 2020 and up to 2022/2024 consistent with Government direction?

**6.5-Staff-115**
<u>Ref: Exh F2-2-3 page 2</u>
Please provide a copy of the Government of Ontario announcement referred to at the above reference.

**6.5-Staff-116**
<u>Ref: Exh F2-2-3 page 4 Chart 1</u>
Please provide in table format the values for the variables noted in Chart 1 at the above reference.

**6.5-Staff-117**
<u>Ref: Exh F2-2-3</u>
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?

**6.5-Staff-118**

Ref: Exh F2-2-3 Attachment 2, Table E2

In Table E2, OPG provides the incremental costs of Pickering Extended Operations (PEO). According to this table, OPG has estimated costs of $240M for restoration of resources to normal levels to enable PEO.

a) Please update Table E2, such that it is consistent with OPG's rate application, especially in regards to the test year expenditures in the table.
b) Please provide a breakdown of costs under the category "Normal Extension of Base & Outage OMA, Projects, Nuclear and Corporate Support Costs" and present it in a format similar to that provided in Chart 2 at Exh F2-2-3 page 6. Please also provide a brief description explaining the work that is planned to be undertaken.
c) Please confirm that the costs noted in Table E2 are incremental and arise only as a result of the PEO project and would not be incurred in the absence of the PEO proposal.
d) In addition to the incremental costs noted in Table E2, are there any other incremental costs related to PEO that are included in the test year budgets? If there are, please identify the costs.
e) The costs shown under the column titled "Post 2020" are OPG's estimate of costs required to operate Pickering post 2020. Please describe in detail how this estimate was developed, identify the underlying assumptions used to develop the cost estimates, provide a breakdown of the costs by year and by major components, such as labour and comment on the major drivers for the costs. Please also comment on how OPG proposes to manage labour costs for the "Post 2020" period such that the operating costs are maintained at levels assumed in the IESO benefit analysis.
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?

**6.5-Staff-119**

Ref: Exh F2-2-3 Attachment 2 page 7

At the above reference OPG discusses the mitigation measures available to it to address pressure tube elongation. OPG states, "Some of the physical modifications which are available would be costly to implement and some of the technical solutions are complex and/or would require increasing the complexity of operational procedures. **Therefore, the preliminary plans to enable the Preferred Alternative include only the less costly physical modifications and less complex technical evaluations**". [Emphasis Added].

a) It appears the plans to enable PEO rely on "less costly physical modifications and less complex technical evaluations", specifically in relation to Fuel Channels. Please explain the rationale for this approach, how it impacts the benefits analysis conducted by the IESO and OPG respectively and comment on how OPG proposes to manage the risks and costs should it later be known that more expensive modifications are needed. Please also clarify if the above statement is in relation to OM&A costs or capital expenditures or both.
b) Table A1 provides a forecast of costs needed to fund modifications arising from the Periodic Safety Review. Please provide a breakdown of the costs, describe the types of modifications and explain why costs related to modifications to the physical plant are being treated as OM&A rather than capital.

**6.5-Staff-120**

Ref: Exh D2-1-2 pages 5-6

With respect to capital expenditures in 2016, at the above reference it states: "*It is expected that new, but not yet defined Pickering capital projects to ensure safe and reliable operations to 2022/2024 will be started in 2017 and use a portion of unallocated funding"*. The Unallocated component of test year capital expenditures is provided in Table 2 at Exh D2-1-2 and reproduced below:

| **Table 2: Capital Expenditure Summary - Nuclear Operations** | | | | | | |
|---|---|---|---|---|---|---|
| Source: D2/T1/S2/Table 2 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| | Budget | Budget | Budget | Budget | Budget | Budget |
| **Row 1: Portfolio Projects - Unallocated ($M)** | **5.5** | **48.8** | **94.6** | **159.4** | **221.6** | **149.8** |
| **Row 2: Pickering Extended Operations Capital Projects ($M)** | | | | | | |

a) Please provide in the format noted in the table above, the capital expenditures related to projects that are intended solely for the purposes of operating Pickering beyond 2020 and that will be funded through the Unallocated capital expenditure budget.
b) Capital projects to enable operation of Pickering to 2022/2024 are scheduled to start in 2017. Is the reason for the 2017 start date dependent on CNSC approval that is expected by June 30, 2017?

**6.5-Staff-121**

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.

**6.5-Staff-122**

Ref: Exh F2-2-3 page 6 Chart 2

a) Please provide OPG's reasons for the large increase in Outage OMA Nuclear Support Costs which increase from $9.9M in 2017 to $62M in 2020?
b) Please clarify whether the outage work related to PEO will be conducted within the outage plan for Pickering (as set out in Chart 2 at Exh F2-4-1).

**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.**

**6.5-Staff-123**

Ref: Exh F2-2-3 Attachment 1, EB-2013-0321

a) In developing the business case to assess the feasibility of operating Pickering from 2016 to 2020, OPG relied on certain assumptions with respect to the Normal operating and capital costs for Pickering for the period 2016 to 2020 and concluded that there was $520M overall system benefit. In table format, please provide separately the assumptions for capital and operating cost relied on in assessing the feasibility of Pickering operations to 2020 and also referenced in the 2012 Business Case Update - Pickering Continued Operations (EB-2013-0321/ F2-2-3-Attachment 1), for each of the years 2016-2020. On a similar and comparable basis please provide the forecast of operating (including all compensation and corporate burdens) and capital costs related to Pickering operations in the current application for the years 2016-2020.
b) Please calculate the variance between the Business Case assumptions and the Test Year forest for each of years 2016-2020. Please comment on the variance in the context of:
    i. The observations in the 2012 Business Case Update which state: "The expected value is somewhat sensitive to the total cost of operating the Pickering Station. ....if OM&A costs were to worsen by 10%, then the incremental value would be reduced by approximately $220 M PV."
    ii. The IESO's analysis, which concludes that PEO "shows a disbenefit when Pickering capital/operating costs are 15-22% greater than the estimates provided by OPG"

**6.5-Staff-124**
Ref: Exh F2-2-3 Attachment 1
At the above reference OPG has included slides from presentations prepared by the IESO that evaluate the economic case for Pickering Extended Operations.

Did the IESO prepare a report or reports in addition to the presentation provided? If such reports were prepared please submit the report(s).

**6.5-Staff-125**
Ref: Exh F2-2-3 page 7
a) It is indicated that OPG conducted its own internal economic evaluation of PEO. Please provide the study.
b) Please compare the assumptions relied on in both studies, particularly with respect to assumptions related to load growth, price of gas-fired generation, Pickering production forecast, and Pickering operating and capital costs.

**6.5-Staff-126**
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?

**6.5-Staff-127**
Ref: Exh F2-2-3 Attachment 1 page 3
The IESO analysis establishes a reference gas price of $5/mmbtu.

How was this estimate/forecast developed? If the IESO has relied on published forecasts to set the reference price, please provide the source and an updated outlook for gas prices in the period 2021-2024.

**6.5-Staff-128**
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?

**6.5-Staff-129**
Ref: Exh F2-2-3 Attachment 1 page 27
At the above reference, the IESO states, "In light of the impact that Pickering capital and operating costs have on the value proposition of extended Pickering operations, it may be worth exploring options for cost control".

What are the cost control measures that OPG proposes to implement to ensure that Pickering operating and capital costs stay at the level assumed in the IESO study?

**6.5-Staff-130**
Ref: Exh F2-2-3 Attachment 1 page 5 and 29
One of the differences between the October 2015 study versus the March 2015 Study is in the outlook for resource requirements from 2015-2032. Please explain the factors that caused the change.

**6.5-Staff-131**
Ref: Exh F2-2-3 Attachment 1 page 32
Please explain and describe the methodology used to calculate the total cost of electricity at page 32.

**6.5-Staff-132**
Ref: Exh F2-2-3 Attachment 1 page 36
At the above reference it is stated that early shutdown of Pickering would present practical challenges related to the securing of replacement supplies within a span of three years. OEB staff notes that the plan for the closure of Pickering in 2020 has been known for some time. In light of this, please explain why the IESO believes that there is inadequate time to source replacement supplies.

**6.5-Staff-133**
Ref: Exh F2-2-3 Attachment 1 page 57
Ref: Exh F2-2-3 Attachment 2 Table 5
a) Please provide the revenue requirement that is attributed to Pickering NGS for each of the test years. Please also identify the impact (versus the status quo) on revenue requirement of the change in capital structure that is proposed in this application. With respect to year 2021, please explain your response in relation to the "Post 2020" costs provided in Table 5 in Attachment 2 of Exh F2-2-3.
b) What is the percent annual impact of the Pickering Extend Operations initiative on the test year revenue requirement?
c) If not already reflected, please update the NPV distributions shown on slide 19 of Assessment of Pickering Life Extension Options: October 2015 Update, as updated November 4 2015, at Exh F-2-3, so that the graph reflects the proposed capital structure contained in this application.

**6.5-Staff-134**
Ref: Exh F2-2-3 Attachment 1 page 73
In the 2013 Long-Term Energy Plan (LTEP) it is noted that early shutdown of Pickering units may be possible if the Clarington transformer station can be placed in service by 2018. Given that the Clarington transformer station is expected to be in-service by 2018 (page73) please describe what has changed, specifically with respect to capacity and demand needs in the East-GTA region, since the release of 2013 LTEP that makes the case for extended operations necessary.

**6.5-Staff-135**
Ref: Exh F2-2-3 Attachment 1 page 73
What is the impact on the net benefit of PEO if it is assumed that the Clarington TS and planned 500/230 kV autotransformer in Milton are placed in-service on schedule, i.e. by 2018 and 2020 respectively?

**Corporate Costs**

**Issue 6.6**
**Are the test period human resource related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension costs, etc.) appropriate?**

**6.6-Staff-136**
Ref: Exh A2-2-1 Attachment 1 page 15
Ref: F2-2-1 page 3
Ref: Exh A2-2-1 Attachment 2 page 15
There are different presentations of information related to human resources related costs. Please provide clarification and definitions.

a) OPG's Business Plan refers to headcount. Does headcount include part time staff and contract staff? Is headcount a year end determination?
b) The evidence at Exh F2-2-1 refers to full-time regular staff, non-regular staff and part time staff. Please provide definitions for these terms.
c) The evidence at Exh F2-2-1 defines augmented staff as "external personnel providing specialized expertise (e.g., engineering) to supplement internal capability and/or to fill temporary vacancies." Are augmented staff considered in headcount or FTE determinations?
d) The business planning instructions state that a change is being introduced in the 2016-2018 business planning process: "FTE calculations for regular labour costing must use the half-year rule. That is, when a regular headcount is added or removed during the year, 0.5 of an FTE must be added or removed in that year for labour costing purposes." Are the FTE calculations and costs related to FTE's consistently represented in the application for the historical and forecast period?
e) Please explain how the FTE are calculated, including reference to the staff categories noted in (b) and (c) above. Is FTE a year end determination?

**6.6-Staff-137**
Ref: Exh F4-3-1 page 5
Ref: EB-2013-0321 Exh A4-1-1 page 1
Ref: Exh F4-3-1 Attachment 1
Business Transformation was initiated in 2011 and finished in 2015 with "nearly 2,700 positions" reduced. The evidence states that efforts to continually improve and manage OPG's resources are embedded in day-to-day operations and business plans.

a) Please specify those efforts and provide specific references to the 2016-2018 business plan.
b) As noted in Exh F4-3-1 Attachment 1, nuclear facility FTE increase in 2016 and for the period 2017-2021 are higher than 2015, when Business Transformation concluded. The evidence from the previous proceeding states that "Business Transformation supports the alignment of OPG's costs with its declining generation capacity … OPG will use attrition to reduce its year-end 2015 staff level by 2,000 employees with the potential for further reductions in later years." What was the timeframe of those "later years"?

**6.6-Staff-138**
Ref: Exh F4-3-1 page 6 and Attachment 1
Ref: Exh F2-1-1 Table 3
At page 6 of Exh F4-3-1, it states that there were 300 retirements in 2015 in the nuclear business. "Over two thirds of the 2015 retirements were in the critical operations, maintenance and technical roles and will need to be replaced."

a) Table 3 of Exh F2-1-1 is a nuclear staff summary. There were 5,430.4 nuclear operations regular FTE in 2015. That number increases to 5,788.6 FTE in 2016. Despite retirements, staffing grew by 358.2 FTE overall, and by an amount well in excess of "over two thirds" of the 2015 retirements related to critical positions where replacement staff was anticipated to be needed. Please explain the increase.
b) Attachment 1 of Exh F4-3-1 lines 10 to 15 summarizes the nuclear allocation FTE in the historical and forecast period. There were 1,628.9 nuclear allocated FTE in 2015. That number increases to 1,773.3 FTE in 2016. How many of the additional FTE are related to critical positions? Please explain the increase beyond the critical positions.

**6.6-Staff-139**
Ref: Exh F2-1-1 Table 3
Ref: Exh F4-3-1 Attachment 1
Ref: Exh 2013-0321 Undertaking J9.7
a) Please explain why FTE at line 7 in Table 3 at Exh F2-1-1 from 2015 to 2021 do not match the nuclear direct FTE on line 8 of Attachment 1 at Exh F4-3-1.
b) Please explain why the 2013 nuclear FTE at line 22 of Attachment 1 at Exh F4-3-1 do not match the 2013 nuclear FTE at line 4 of Undertaking J9.7 of the previous

proceeding. Are the differences related to the banked overtime referred to in the footnote to Figure 3 of Exh F4-3-1?

c) Did the Goodnight study at Exh F2-1-2 Attachment 2 consider the adjusted number of FTE referred to in the footnote to Figure 3 of Exh F4-3-1?

**6.6-Staff-140**

Ref: Exh F4-3-1 Attachment 1

Ref: 2015 Annual Report of the Office of the Auditor General of Ontario (Dec. 2, 2015)

Nuclear facility FTE increase in 2016 and for the period 2017-2021 are higher than 2015, when Business Transformation concluded.

a) Are any of the FTE added after 2015 former OPG employees?
b) If yes to (a), how many?
c) If yes to (a), was the process described at page 630 of the 2015 Auditor General of Ontario Report (below) followed?

> OPG also implemented a new procedure for rehiring of retirees that requires a minimum waiting period of one year between the time an employee retires and when that employee can be rehired, and then only with a maximum contract length of one year. Any such hire must also receive senior management approval. Exceptions may be made to accommodate employees in the nuclear field because of the limited availability of highly skilled workers.

**6.6-Staff-141**

Ref: Exh A2-2-1 page 2 Attachment 1 page 15

Ref: Exh F2-1-1 Table 3

At page 15 of the business plan it states, "Staffing levels from ongoing operations are expected to continue to decrease after 2018…The decrease over the 2019-2021 period reflects reductions in staffing levels as the Pickering station begins to approach its end of life …"

a) At page 2 of Exh A2-2-1, it states that the planning assumptions include Pickering 2022/2024. If so, why are there reductions in staffing levels in 2019-2021?
b) Does the business plan and the nuclear staff summary reflect the allocation of Darlington staff, from units undergoing refurbishment, to Pickering?

**6.6-Staff-142**

Ref: Exh F4-3-1 page 6, Figure 3

Figure 3 has a line showing total compensation per FTE.

a) Does the total compensation per FTE include the value of the lump sum payment and share performance plan discussed at Exh F4-3-1 page 17? If it does not, please update the table to include this remuneration.
b) Further to question (a), does the total compensation per FTE include all compensation in any form provided to OPG employees? If not, please elaborate.

c) In its Total Compensation Benchmarking Study, Towers compares OPG's "Total Direct Compensation" (which is average salary + target bonus + nuclear and other allowances) with several comparator groups. How does Total Direct Compensation map to Figure 3? Is it the "base salaries and incentives" line?
d) Please prepare a chart showing the average total compensation per employee from 2010-2021 for the management, PWU and Society groups. Please include all compensation, including the lump sum payments and the share performance plan. OEB staff suggests that OPG use the format of EB-2013-0321 Undertaking J9.7 to present this data.

**6.6-Staff-143**

Ref: Exh F4-3-1 page 6

The evidence states that "In 2016, staffing levels for OPG's Nuclear facilities are expected to increase by over 600 FTEs due largely to the DRP and, to a lesser extent, the workforce renewal required to sustain Pickering operations."

a) There will be approximately 1,700 external contractors working on DRP.
   i. Please provide more detail on the need for an additional 600 OPG FTEs for DRP.
   ii. If not provided in (i) above, please provide a functional summary for the DRP FTEs, e.g. engineers, business analysts, administrative assistants, etc.
   iii. Please provide the breakdown for the DRP FTEs by management, Society and PWU.
b) Please provide a breakdown on the number of additional FTEs that will be associated with the DRP, and the number of additional FTEs that will be associated with sustaining Pickering operations. Please provide the response as separate line items (i.e. lines for DRP regular and non-regular, and lines for Pickering extended operations regular and non-regular) in the format of Table 3 of Exh F2-1-1 and Attachment 1 to Exh F4-3-1.
c) Will the additional FTEs hired for sustaining Pickering operations be "term employees" as described at Exh F4-3-1 p. 7?
d) Why do the numbers of FTEs fall by approximately 500 from 2017-2021?

**6.6-Staff-144**

Ref: Exh F4-3-1 page 8

The evidence states that "OPG…negotiated agreements with both the PWU and Society in 2015 that will keep wage escalation below inflation. Both agreements provide for a one percent escalation increase each year…"

a) Please file a copy of the PWU and Society collective agreements.
b) Is the one percent escalation in addition to the cost of living adjustments discussed in the previous paragraph on page 8? How much escalation is associated with the cost of living adjustments?

**6.6-Staff-145**

Ref: Exh F4-3-1 pages 12-13

The evidence states that overtime expenses are expected to fall by approximately 50% from 2013 to 2021.

a) Given the relatively stable FTE numbers over this period, how will OPG manage to reduce overtime expenses by 50%?
b) Figure 9 shows that the projected overtime costs are essentially stable from 2014 through 2019, and then fall significantly in 2020 and 2021. Why is there a significant drop-off in 2020 and 2021?

**6.6-Staff-146**

Ref: Exh F4-3-1 page 12

In prior periods, OPG has complied with compensation restraints for management staff. To address issues related to salary compression and management retention, "OPG has re-instated its annual base pay increase program for Management staff below the Vice President level and obtained OPG Board approval of funding for 2016. Under this program, salary increases are performance based, linked to external labour markets in line with the benchmarking results discussed in section 5.0, and enable some compression issues to be addressed where appropriate. The cost of this program is being off-set through savings associated with Management headcount reductions and movement towards market compensation for some Management positions.

a) What is the cost of the program?
b) What were the savings associated with management headcount reductions?

**6.6-Staff-147**

Ref: Exh F4-3-1 pp. 15-16

The evidence discusses changes to pension and benefits.

a) Figure 10 shows the employee/employer contribution ratio. Does this figure relate to pensions only, or does it include OPEBs? If it does not, please provide a chart showing the employee/employer ratio including OPEB costs.
b) Do retirees receive the same benefits as current employees?
c) The evidence states that the mandate of the Advisory Council on Government Assets included "obtaining a multi-year agreement, wage increases that were neutral to Ontario taxpayers and electricity ratepayers, and longer term solutions to help address pension stability." Did the agreements reached with the PWU and the Society result in wage increases that were neutral to electricity ratepayers? If yes, please provide the details.
d) The evidence describes three concessions that were negotiated with the unions respecting pensions: increased employee contributions, changes to the earnings basis for pensions, and changes to retirement eligibility for undiscounted pensions. Please provide the anticipated annual savings over the test period for each of these changes. Are these savings included in Figure 3 at F4-3-1 p. 6?

e) How does the "Rule of 85" compare with pension plans in the Ontario public service generally?
f) Approximately how much money is expected to be saved annually in the years after the test period on account of the concessions described in question (d)?
g) In return for the concessions described in question (d), PWU and Society employees received a "lump sum payment" and a number of Hydro One Limited shares (the Share Performance Plan). Please provide the annual costs for these measures. Are these costs included in Figure 3 at F4-3-1 p. 6?
h) Is OPG targeting a 1:1 contribution ratio for some point in the future? If so, when? What is the revenue requirement impact in the test period for contribution ratios higher than 1:1? Please provide the answer for each year, and on an accrual basis and a cash basis.

**6.6-Staff-148**

Ref: Exh F4-3-1 p. 18

The evidence states that "OPG's Total Direct Compensation" is at market. Total Direct Compensation reflects cash compensation paid to employees, excluding overtime. It also does not include pensions and benefits.

a) Why is overtime excluded from Total Direct Compensation? Was the decision to exclude overtime made by Willis Towers Watson (Towers), or by OPG?
b) Did Towers conduct any analysis with respect to overtime costs or practices at OPG?
c) Does Total Direct Compensation include the lump sum payment and Share Performance Plan? If not, why not?
d) Has OPG assessed whether its total compensation (i.e. all salary, bonuses, overtime, pensions, benefits, OPEBs, etc.) is at market?

**6.6-Staff-149**

Ref: Exh 4-3-1 pp. 19-23

OPG retained Towers to conduct a compensation study. At figure 11 OPG presents a comparison between the results of the Towers study (2015) and the compensation study produced for OPG by AON Hewitt ("AON") for 2013. The Towers study generally shows more favourable OPG results compared to the AON study.

a) Please provide the retainer letter or other instructions OPG provided to Towers when they were retained to do the compensation study.
b) Please discuss any methodological or other significant differences between the Towers study and the AON study. For example, were the same comparators used? Are the positions reviewed the same?
c) Some of the results are markedly different from 2013 to 2015. For example, the PWU "utility" figures went from 21% above market in 2013 to only 4% above market in 2015. The management nuclear figures went from 3% below market in 2013 to 27% below market in 2015. Please provide any details that can help explain such a large shift over a short period of time.
d) Why did OPG select Towers instead of AON to conduct the 2015 study?

e) On page 20, there are three references to OPG employee compensation being at or below market (at lines 4, 13, and 19). Please confirm that "compensation" here refers to Total Direct Compensation (i.e. cash compensation) and excludes overtime, pensions and benefits, etc.
f) On pages 20-21, OPG observes that its "general industry" comparisons would be closer to market if measured against similar positions at utility companies. Does OPG believe that the make-up of the comparators in the general industry segment is faulty? Does Towers believe that the make-up of the comparators in the general industry segment is faulty?

**6.6-Staff-150**

Ref: 2013 Annual Report of the Office of the Auditor General of Ontario (Dec. 10, 2013)

The Auditor General's 2013 report noted that OPG payroll data indicated that a large number of employees received salaries that exceed the maximum set out in the base salary schedule.

a) Is receipt of salary above base salary schedule still occurring?
b) If yes, how many staff are affected?
c) If yes, was Towers' analysis based on salary schedules or actual salaries?

**6.6-Staff-151**

Ref: Exh F4-3-1 pp. 21-22, Exh. F4-3-1 Attachment 3

The evidence presents a direct comparison between wages at OPG and at Bruce Power.

a) Please confirm that the comparison includes wages only, and does not include pensions, benefits, OPEBs, overtime, lump sum payments, share performance plan, etc.
b) Towers prepared a total compensation benchmarking study. The study included analysis of OPG's direct compensation as compared against a "nuclear authorized" group, which includes Bruce Power. Does Towers believe that the analysis comparing OPG only to Bruce Power is preferable to the analysis comparing OPG against the nuclear authorized group as a whole?

**6.6-Staff-152**

Ref: Exh F4-3-1 Attachment 2

The Towers Total Compensation Benchmarking Study benchmarked 78% of OPG incumbents (corporate wide). However, only half of the Society nuclear authorized staff and Society represented general industry staff were benchmarked.

a) Please explain the low level of representation in the benchmarking.
b) Is there any correlation between these positions not benchmarked by Towers and the positions not benchmarked by Goodnight in the report at Exh F2-1-1 Attachment 2?

**6.6-Staff-153**

Ref: Exh F4-3-1 Attachment 2

The Towers Total Compensation Benchmarking Study provides a compensation analysis and a pension and benefits analysis.

a) Nine of the ten comparators in the "nuclear authorized" group are based in the United States; accordingly Towers converted their compensation figures into CAD. Please confirm that the results of the nuclear authorized comparison can be heavily influenced by fluctuating exchange rates.
b) At page 11, the report states: "OPG's compensation philosophy defines a target market position at the … 75th percentile for the Nuclear Authorized Segment (based on role complexity)." Does Towers agree that the 75th percentile is the most appropriate comparison point for the Nuclear Authorized Segment? Please elaborate.

**6.6-Staff-154**

Ref: Exh F4-3-1 Attachment 2

At page 26, the methodology for the pensions and benefits analysis is discussed.

a) Does the pensions and benefits analysis include OPEBs? If not, why not?
b) At page 26 the report states: "Benefits no longer available to new hires are not considered." Why not? What benefits were excluded because of this decision?
c) Page 27 presents the value of OPG's and comparator organizations' pensions and benefits as a percentage of base salary. What is included in "base salary?"
d) OEB staff is having difficulty understanding the 10% adjustment that has been made for non-authorized roles in nuclear plants (described at pages 7 and 34 of the report). Which employees comprise the "Non-Authorized Nuclear segment"? The report states that for many roles the salaries are comparable, but nuclear operations management roles carry a premium. Was the 10% premium applied only to nuclear operations managers? Please list the positions to which the premium was applied. Please present the results of the report without applying the 10% adjustment.
c) In considering the relative value of OPG's pensions and benefits (pages 28-29 of the report), what was included as being a pension or benefit? At Exh F4-3-2 page 1 OPG defines its pension and OPEB programs as consisting of the registered pension plan, a supplementary pension plan, other post-employment benefits such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability benefits for current employees. Were all of these things included by Towers in its analysis of pensions and benefits?

**6.6-Staff-155**

Ref Exh F4-3-1, Attachment 2, page 26

As part of their total compensation benchmarking exercise, Towers compared the level of pension and benefits offered by OPG with those offered by comparator organizations (market) used in the study. The study determined that OPG's pension and benefits as a % of base salary is above the 50th percentile of the market. Please quantify (estimate) the impact on the test period if the revenue requirement had been determined using the market level of pension and benefits from the study (i.e. 50th percentile).

**6.6-Staff-156**

Ref: Exh F4-3-2 page 5

Chart 1 shows the annual nuclear pension and OPEB cash amounts.

Why is there a significant drop in the cash amount for pensions between 2016 and 2017?

**6.6-Staff-157**

Ref: Exh F4-3-2

Ref: EB-2013-0321 Exhibit JT2.12, Attachment 1

In EB-2013-0321, OPG filed a CHRC Briefing Report prepared by Towers Watson. The report reviewed the challenges OPG was facing regarding the costs of its employee pensions and benefits.

a) The report filed in EB-2013-0321 had last been updated in 2013. Has the report been updated since then? If so, please provide a copy.
b) Has OPG received any other reports regarding the costs and sustainability of its employee pensions and benefits? If so, please provide.
c) The report assessed the sustainability of OPG's pensions and benefits plans against four metrics. The report concluded that all four metrics had been exceeded (p. 2, 6-9). Does OPG still exceed the thresholds established in all four metrics?
d) The report identified six "interventions" that OPG could undertake to improve the sustainability of its pensions and benefits. Please describe what activities OPG has taken with regard to these six interventions, and the results of these activities.
e) At page 2, the report states that (as of 2013) "OPG's P&B plans are unsustainable". At page 11 it states: "a number of current cost levels exceed the thresholds which OPG views as necessary to maintain a sustainable business (across all key measures)". Are OPG's pensions and benefits plans currently sustainable? Do the current costs of pensions and benefits allow OPG to maintain a sustainable business? If not, how does OPG plan to address this situation? Will ratepayers be asked to provide additional funding for pensions and benefits now or in the future?
f) At page 11, the report states: "the risk of costs escalating far beyond an affordable level is very plausible." Is this statement still accurate?

**6.6-Staff-158**

Ref. Exh F4-3-2, Chart 1 and Attachment 1

Chart 1 presents the forecasted pension and OPEB cash amounts included in the test period revenue requirement. OPG indicates that the amounts are derived from the actuarial valuation performed by AON Hewitt and included in Attachment 1 of this exhibit. Please provide a table that reconciles the revenue requirement amounts in Chart 1 to the "Estimated Employer Pension Contributions / Benefit Payments" line in Schedules 1-6 of the AON Hewitt valuation.

**6.6-Staff-159**

Ref. Exh F4-3-2, page 7

Ref: EB-2013-0321 Oral Hearing Tr Vol 13 page 18

Up until the OEB decision in EB-2013-0321, OPG had been recovering its pension and OPEB costs in rates on an accrual basis. In the oral hearing of the previous proceeding, OPG confirmed that any excess recovery is not set aside into any fund.

Please describe what OPG has done with any recoveries in excess of cash contributions /benefit payments.

**6.6-Staff-160**

Ref. Exh F4-3-1, page 8

OPG indicates that the current collective agreements with the PWU and Society are due to expire on March 31, 2017 and December 31, 2018, respectively.

The above contracts expire within the test period. Accordingly, what assumptions been built into the test period actuarial valuations to factor in estimates related to the impact of any anticipated changes in the level of pension and OPEB benefits from the upcoming bargaining (assuming that further pension and OPEB reforms are planned through this round of bargaining)? Please provide a table that summarizes the expected impact over the test period.

**6.6-Staff-161**

Ref. Exh F4-3-2, Attachment 1, page 6

The actuary describes the methodology and other considerations used in determining the expected long-term rate of return on plan assets of 6.00%.

a) Please provide a calculation for the average actual rate of return on plan assets over the last 10 years (please also include a table that summarizes the 10 year data used to perform this calculation). If the period contains an outlier year, please remove the impact of the outlier from the calculation (i.e. normalize).
b) Based on the above calculation, compare this historical average to the rate used in the actuarial valuation. What would be the impact on the test period revenue requirement had the expected long-term rate of return been based on the 10-year historical average?

**6.6-Staff-162**

Ref. Exh F4-3-2, Attachment 1, page 6

The discount rates used in the actuarial valuation have been set with reference to those representative of AA-corporate bond yields in Canada having a similar duration to the liabilities of the plans. Please provide the quoted source for each rate used.

**6.6-Staff-163**

Ref. Exh F4-3-2, Attachment 1, page 6

Similar to the table provided on page 49 of the December 31, 2015 Management Discussion and Analysis, please perform a sensitivity analysis on the pension and OPEB test year revenue requirement for the following management assumptions:

a) Inflation rate - show the impact of an increase / decrease of 0.25%
b) Discount rate – show the impact of an increase / decrease of 0.25%
c) Expected long-term rate of return - show the impact of an increase / decrease of 0.25%
d) Salary Increases return - show the impact of an increase / decrease of 0.25%
e) Health care cost trend rate - show the impact of an increase / decrease of 1.00%

**6.6-Staff-164**
Ref: Report on the Sustainability of Electricity Sector Pension Plans to the Minister of Finance (March 18, 2014)
Ref: Government of Ontario News Release (July 6, 2016)
In 2014, the Special Advisor to the Minister of Finance filed a report on electricity sector pension plans. The report stated that both Hydro One and "OPG are involved in the technical working group. They should consider if joining a new pooled asset management entity for public sector SEPPs will provide them with anticipated advantages."

On July 6, 2016, the Government of Ontario announced the creation of the Investment Management Corporation of Ontario (IMCO), which will provide investment management and advisory services to participating organizations in Ontario's Broader Public Sector to improve the management of broader public sector investment funds, including public sector pensions.

What is the status of OPG's review with respect to joining a new pooled asset management entity?

**Issue 6.7**
**Are the corporate costs allocated to the nuclear businesses appropriate?**

**6.7-Staff-165**
Ref: Exh F3-1-1 Table 7
a) Please provide reasons for the 16% increase in Supply Chain costs from 2015 to 2016. Please also explain if the factors that caused the increase are expected to continue in the test years.
b) The actual expenditures for 2013 - 2015 average $44M. The average forecast for Supply Chain costs for the period 2017-2021 is $48.3M. What are the reasons that have caused OPG to increase the test year forecast for Supply Chain costs by 10% compared to actuals?

**6.7-Staff-166**
Ref: Exh F3-1-1 Table 7

a) What are the reasons for the increase in Real Estate Service costs from $82.5M in 2015 to $94.5M in 2017? Please identify the factors that caused the increase and are these factors expected to continue in the test years?
b) The average of test year costs is $95.3M and represents a 12% increase compared to the average of actual costs for the most recent period (2013-2015), which is $84.7M. What are the factors that have caused OPG to increase the test year forecast for Real Estate costs by 12% compared to actuals?

**6.7-Staff-167**

Ref: Exh F3-1-1 Table 3

Please provide the reasons for the increase in Corporate Centre costs from $26.9 M in 2014 to $44.3M in 2016. What are the factors that caused the increase and does OPG expect these factors to continue in the test years?

**6.7-Staff-168**

Ref: Exh F3-1-1 Attachment 1 page 6

The Hackett Group benchmarked corporate support functions and costs. Some OPG functions were excluded from benchmarking to facilitate comparisons.

Please explain why training, security and warehouse management were excluded from the comparisons.

**6.7-Staff-169**

Ref: Exh F3-1-1 page 14

Ref: EB-2010-0008 Exh F5-3-2

Figure 1 on page 14 presents a summary of corporate cost benchmarking results.

a) Are the peer results at column (c) at 2014?
b) In EB-2010-0008, OPG filed a Finance benchmarking report prepared by the Hackett Group. The report included reporting by peer group quartiles. What was OPG's performance by quartile for each corporate function in 2010 and 2014?
c) For the 2017-2021 test period, please provide IT cost per end user, HR cost per employee, finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue.

**6.7-Staff-170**

Ref: Exh F3-1-1 page 14

One of the corporate functions benchmarked by Hackett was executive and corporate services (ECS) function. Footnote 11 on page 14 lists the 11 sub-categories within ECS.

a) Are some of the groups within ECS included in those that were not benchmarked in the Towers report at Exh F4-3-1 Attachment 2?
b) Are some of the groups within ECS included in those that were not benchmarked in the Goodnight report at Exh F2-1-1 Attachment 4?
c) ECS cost in 2010 and 2014 is provided as a % of revenue. Please provide the ECS costs in dollars for 2010 and 2014.

d) Please provide the 2010 and 2014 ECS costs allocated to the nuclear business. Please provide the forecast ECS costs allocated to the nuclear business for each year 2017-2021.

**6.7-Staff-171**

Ref: Exh F3-1-1 page 15 Attachment 1 page 16

At page 16 of Attachment 1, some of the individual ECS functions are compared with peers.

a) At page 15 of Exh F3-1-1 OPG explains that its real estate costs are affected by the large number of facilities and geographic spread. There are only two nuclear facilities in close proximity. How does the 2014 nuclear business real estate cost of $83.3M compare with peers?
b) How does the 2014 nuclear supply chain cost of $42.5M compare with peers?
c) OPG states that its performance relative to peers is influenced by labour costs and would be impacted to the extent that peers are non-unionized. How many of the peers listed on page 9 of Attachment 1 to Exh F3-1-1 are non-unionized?

**6.7-Staff-172**

Ref: Exh F3-1-3

Exh F3-1-3 reviews Regulatory Affairs costs.

Please complete the following table for all one-time costs related to this application.

| | | Historical Year(s) | 2016 Bridge | 2017 Test |
|---|---|---|---|---|
| 1 | Expert Witness costs | | | |
| 2 | Legal costs | | | |
| 3 | Consultants' costs | | | |
| 4 | Incremental operating expenses associated with staff resources allocated to this application. | | | |
| 5 | Incremental operating expenses associated with other resources allocated to this application. [1] | | | |
| 6 | Intervenor costs | | | |

1 Please identify the resources involved.

**Issue 6.8**
**Are the centrally held costs allocated to the nuclear business appropriate?**

**6.8-Staff-173**

Ref: Exh A1-3-4, page 3

Ref: Exh F4-4-1

OPG is subject to the *Nuclear Liability Act* (Canada), which governs civil liability for nuclear damage in Canada. On February 26, 2015, the federal *Nuclear Liability and*

*Compensation Act* under Bill C-22 received Royal Assent. OPG forecasts increased nuclear insurance premiums starting in 2016.

What is the status of the Governor in Council that will replace and repeal the *Nuclear Liability Act* (Canada)?

**Depreciation**

**Issue 6.9**
**Is the proposed test period nuclear depreciation expense appropriate?**

**6.9-Staff-174**
Ref: Exh F4-1-1 page 3
The DRC performs regular reviews of the service lives of generating stations and a selection of asset classes with the general objective of reviewing all significant asset classes for the regulated assets over a five-year cycle.

a) Has the process in which DRC performs its review changed since EB-2013-0321? If yes, please explain the change.
b) How does OPG determine which nuclear assets classes are considered significant and warrant a review?
c) Please quantify the amount of nuclear assets that are not considered significant for review. How much do these assets account for out of total regulated assets?
d) Please provide the 2014 DRC report.

**6.9-Staff-175**
Ref: Exh F4-1-1 page 4
OPG states that as the EB-2013-0321 Depreciation study, which was based on December 31, 2012 asset net book values was conducted less than five years ago, OPG has not commissioned a new independent review of service life estimates for the regulated assets:

a) Please indicate when OPG is planning on commissioning a new independent review of the service life estimates.
b) If there are material changes as a result of such an independent study, how does OPG plan to address the changes and its impact to depreciation?

**6.9-Staff-176**
Ref: Exh F4-1-1 page 5
It's stated that the Province's announcement and the execution of the ARBPRIA provided OPG with the necessary evidence to align the Bruce EOL dates for accounting purposes with the ARBPRIA effective, December 31, 2015.
a) Was OPG involved in establishing the end of life date as set out in the ARBPRIA? If yes, please explain OPG's role.
b) Has OPG assessed if the end of life dates set out in the ARPRIA are reasonable?
    i. If yes, please explain the assessment OPG performed.

ii. If no, please explain why not and why OPG has chosen to align the Bruce EOL date with the date per the ARPRIA.

**6.9-Staff-177**

Ref: Exh F4-1-1 page 6, page 3 of Attachment 1, Table 2 and Exh B3-4-1, Table 2

OPG proposes the EOL date for Pickering station to be December 31, 2020.

a) Pickering Units 5 to 8 EOL was extended by 8 months due to the confidence that was achieved through work on the Fuel Channel Life Extension Project and execution of inspection and technical work programs. Please provide further details and explain the factors that led OPG to conclude on the level of confidence achieved.
b) In Attachment 1, the 2015 DRC Report, it is indicated that all four units are expected to be technically fit to safely operate until at least December 31, 2020 based on the Fuel Channel Life Extension project.
   i. Based on the project, what is the furthest date that all four units are expected to be technically fit to safely operate?
   ii. Please explain why OPG proposes December 31, 2020 as the EOL date and not any date further in the future.
c) In Table 2, depreciation and amortization expense increases from \$127.5M in 2013 to \$233.3M in 2020, then drops to \$53.1M in 2021.
   i. Please explain whether the decrease in depreciation from 2020 to 2021 is entirely due to the EOL of Pickering Units 1,4 and 5 to 8.
   ii. Pickering station is at EOL by December 31, 2020. From Exh B3, there is \$53.1M depreciation and amortization expense in 2021 that is mainly for newly in-service additions. Please explain why there is newly in-service depreciation in 2021 and what this depreciation pertains to.
d) Please explain OPG's treatment of gains and losses in relation to the Pickering station assets that have reached EOL at the end of 2020.
   i. Have any gains or losses been identified?
   ii. If yes, please quantify the gains and losses and indicate where they are included in OPG's application.

**6.9-Staff-178**

Ref: Exh F4-1-1 page 6

OPG is undertaking initiatives to extend Pickering operating beyond 2020.

a) Has OPG capitalized projects relating to the extension of Pickering operations? If yes, how much is the related depreciation expense over the test period?
b) OPG will seek OEB's approval of an accounting order related to any future changes to the Pickering EOL date. If OPG is able to extend operations, please explain how this will impact depreciation and amortization expense as well as any gains and losses recognized in the application.
c) If OPG is unable to extend operations, please explain how this will impact depreciation and amortization expense as well as any gains and losses recognized in the application and how OPG plans to address the impacts to rates.

d) How will the Capacity Refurbishment Variance Account or any of the other existing DVAs be impacted, if it is impacted?

**6.9-Staff-179**
Ref: Exh F4-1-1 Attachment 1, page 3 and Exh D2-2-1 page 2
Per Attachment 1, the 2015 DRC Report, Darlington EOL date was extended a year to December 31, 2052 based on the approved refurbishment outage schedule and target return to service dates for each unit and continuing to assume a 30-year post refurbishment operating life. However, per Exh D2, all four Darlington units will be under refurbishment until February 2026, except unit 2 until February 2020. Please explain how the proposed EOL date of 2052 reconciles with the 30-year post refurbishment date.

**6.9-Staff-180**
Ref: Exh F4-1-1, page 4 and Table 2
Depreciation for the Darlington Refurbishment Program increases significantly in 2020 to $159.1M and 2021 to $177.6M per Table 2. The 2014 and 2015 DRC report recommended no changes to asset classes.

a) Please provide a listing of 2020 and 2021 DRP in-service addition asset classes and their corresponding values for asset classes with service lives that are newly established (i.e. the asset class has never been previously reviewed by the DRC or any independent study).
b) Please explain how the asset service lives for these assets were determined and what steps were taken to ensure that the asset lives are appropriate.

**6.9-Staff-181**
Ref: Exh F4-1-1 Table 2
For ARC depreciation and amortization:

a) In 2021, depreciation decreases from $50.3M to $18.7M. Please explain the reasons for the decrease.
b) Please explain whether there have been any changes to ARC depreciation due to the Darlington Refurbishment Program.
    i. If yes, please quantify the amount.
    ii. If no, please explain why not.

**6.9-Staff-182**
Ref: Exh A2-1-1, Attachment 5, page 23 and Exh F4-1-1 Table 2
The 2015 depreciation expense is $428M per Note 4 of the 2015 prescribed financial statements. Actual depreciation expense is $298M per Table 2 in the rate application. Please reconcile and explain the difference between the two depreciation numbers.

**6.9-Staff-183**
Ref: Exh D2-1-3, page 12 and Table 4, and Exh B3-3-1, Table 1

In-service additions are presented in Table 4 and Table 1. Table 4 includes a breakdown for Supplemental In-Service Forecast, which represents undefined projects and late completion projects. The undefined projects are unallocated.

a) Table 1 shows in-service additions by prescribed facility. Please reconcile Tables 1 and 4.
b) Please explain how the Supplemental in-service forecast amounts in Table 4 were allocated to the prescribed facilities in Table 1.
c) Please explain how depreciation expense is forecasted for undefined projects.
d) Please quantify the depreciation expense associated with the undefined projects over the test period.

**Income and Property Taxes**

**Issue 6.10**
**Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?**

**6.10-Staff-184**
<u>Ref: Exh F4-2-1</u>
Please provide the 2015 income tax returns and a reconciliation of the consolidated taxable income to the regulatory taxable income for the prescribed facilities.

**6.10-Staff-185**
<u>Ref: Exh F4-2-1, page 1</u>
OPG is seeking approval for nuclear income tax expense of ($18.4)M, ($18.4)M, ($18.4)M, $51.2M, and $51.7M from 2017 to 2021 respectively.

The ($18.4)M for 2017 to 2019 appears to be entirely as a result of SR&ED ITCs. Please explain why OPG is proposing negative taxes instead of carrying the SR&ED ITCs forward to be used in a future test year.

**6.10-Staff-186**
<u>Ref: Exh F4-2-1, page 2</u>
ITCs for SR&ED expenditures are recognized in the calculation of regulatory income taxes.

a) Please indicate if there is any other ITCs OPG qualifies for.
b) If yes, please identify and quantify the ITCs.
c) Please indicate whether they are recognized in the calculation of regulatory income taxes. If they are not, please explain why not.

**6.10-Staff-187**
<u>Ref: Exh F4-2-1, page 10, and Table 3</u>
Per page 10, OPG can claim a non-refundable ITC for SR&ED. In Table 3, 2014 regulatory income taxes were ($56.0M) mainly as a result of a $61.7M SR&ED ITC.

a) Please confirm that OPG did not receive a refund for the $61.7M SR&ED ITC.
b) Please explain the treatment of the $61.7M SR&ED ITC and whether it was carried forward and applied to the calculation of regulatory income taxes in 2015 or future years.

**6.10-Staff-188**

Ref: Exh F4-2-1, Table 3 and Exh I1-2-1, Table 2a

a) The 2015 Nuclear SR&ED ITC included in the EB-2013-0321 Payment Amount Order is $9.4M as seen in in Table 2a. Please confirm that there will be no true up to the actual 2015 SR&ED ITC of $31.9M (i.e. it will not be included in the Income and Other Taxes Variance Account).
b) Please provide a continuity schedule of the SR&ED credits available, used against regulatory income tax, carried forward or back from 2013 to 2021.

**6.10-Staff-189**

Ref: Exh F4-2-1, page 10, Table 3a and Exh H1-1-1, pages 11-12

Page 10 indicates that OPG recognizes 75% of the estimated ITCs for taxation years that are subject to audit. To the extent the ultimate percentage of recognition for SR&ED ITCs differs from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG records the difference in the Income and Other Taxes Variance Account.

a) Please confirm that the variance account is only to true up the 75% to the percentage of recognition resulting from a tax audit and is not a true up to the actual SR&ED credit claimed.
b) Please indicate how often SR&ED audits occur.
c) OPG has forecasted SR&ED ITCs to be $18.4M for each year from 2017 to 2021.
   i. Is this amount 75% of the total estimated SR&ED ITC?
   ii. Please explain how the $18.4M SR&ED ITC was derived and why OPG proposes that it be the same amount each year from 2017 to 2021.
d) Please provide a comparison of forecasted and actual SR&ED from 2013 to 2015.
e) OPG has forecasted additions for Taxable SR&ED ITCs to be $18.4M each year from 2017 to 2021 and deductions for SR&ED Qualifying Expenditures to be $27.7M each year from 2017 to 2021.
   i. Please explain how these amounts were derived and why OPG proposes it to be the same amount each year from 2017 to 2021.
   ii. Please explain the correlation between the forecasted additions, deductions and ITC amounts relating to SR&ED in Table 3a.

**6.10-Staff-190**

Ref: Exh F4-2-1, page 8 and Table 4

Page 8 states that amounts recognized for accounting purposes as regulatory assets or liabilities in the period are reversed from regulatory earnings before tax in determining OPG's actual taxable income. An example of this is in Table 4, lines 21-23, column A. However, column A represents OPG's 2014 tax return and lines 21-23 include amounts for regulatory assets or liabilities. These amounts are adjusted to $0 in the regulatory tax calculation.

Please clarify whether the amounts recognized for regulatory assets or liabilities are included in OPG's 2014 taxable income of $392.4M.

**6.10-Staff-191**

Ref: Exh F4-2-1, page 12 and Table 3a

Page 12 states that the decrease in 2021 of regulatory taxable income before the application of losses is largely attributable to lower depreciation and amortization expense related to the Pickering station, which is assumed to be close to fully depreciated by the end of 2020. Table 3a shows the addition of depreciation and amortization expense to decrease from $524.9M in 2020 to $338.1M in 2021. CCA deductions are relatively consistent from $594.8M in 2020 to $597.0M in 2021.

a) How much UCC is remaining for the Pickering station by the end of 2020?
b) When does OPG expect to claim the remaining CCA deductions pertaining to the Pickering station?

**6.10-Staff-192**

Ref: Exh F4-2-1, Tables 3a and 3b

Table 3b calculates regulatory earnings before tax. The calculation includes line 13a for the reduction in total regulatory income taxes due to loss carry-over, which is based on the tax loss carry-over calculated in Table 3a. The starting point of Table 3a is regulatory earnings before tax, which is calculated from Table 3b.

Please explain how the calculations pertaining to the tax loss carry-over in tables 3a and 3b are calculated and whether the calculation is circular.

**6.10-Staff-193**

Ref: Exh F4-2-1,Tables 3a and 3b

In Table 3, there is a deduction for the reversal of return on rate base recorded in deferral and variance accounts for 2013 to 2016. There is no such deduction in Table 3a for 2017 to 2021.

Please explain what this deduction is for and why it is only applicable to 2013 to 2016.

**6.10-Staff-194**

Ref: Exh F4-2-1, Tables 3b, 5 -12

For the CCA tables:

a) Please explain what the assets subject to the "rolling start" rule pertain to and whether they relate to the Darlington Refurbishment Program accelerated CCA referenced in Table 3b, Note 3.
b) Per Table 3b, Note 3, for the Darlington Refurbishment Program accelerated CCA:

   i. It is indicated that the accelerated CCA election was noted in EB-2013-0321. Please provide the specific reference that discusses this election in EB-2013-0321.
   ii. Please explain if the same election was made in OPG's tax filings.
   iii. Please approximate the impact to CCA if the accelerated CCA election was not made for 2017 to 2021.

c) For amounts in the Cost of Acquisition column:
   i. Please explain how the amounts are derived
   ii. Please reconcile the amounts with in-service addition amounts presented Exhibit B3, Tab 3, Schedule1, Table 2.

**6.10-Staff-195**
<u>Ref: Exh F4-2-1, Table 4 and Attachment 1</u>
The breakdown of line items for additions and deductions as shown in Table 4 is different than that as shown in the 2014 tax return. Please explain why a different breakdown of line items for additions and deductions is used in the calculation of regulatory taxable income.

**6.10-Staff-196**
<u>Ref: Exh F4-2-1, Table 4</u>
In the reconciliation of OPG's tax return to regulatory income tax for prescribed facilities, the deduction for Construction in Progress Interest Capitalized of $61M in the tax return is removed as a deduction in the regulatory tax calculation (column h). Please explain why the deduction in the tax return is not included as a deduction for regulatory taxes even though capitalized interest is eventually included in rate base.

**Other Costs**

**Issue 6.11**
**Are the asset service fee amounts charged to the nuclear businesses appropriate?**

**6.11-Staff-197**
<u>Ref: Exh F3-2-1</u>
At the above reference it is noted that pursuant to a Shareholder Declaration and Resolution, OPG has decided to sell its head office at 700 University Avenue, Toronto. OPG also states that the Shareholder Declaration and Resolution also requires that OPG transfer the portion of the proceeds from the sale equal to the after-tax accounting gain on sale, net of transaction costs.

a) Please confirm that asset service fees previously charged in relation to 700 University Avenue have been replaced with lease payments and are considered a Real Estate Service cost.
b) Please provide the Shareholder Declaration and Resolution that is referenced above.

c) What is the current status of the sale and when is the sale expected to be completed?
d) Is OEB staff correct in understanding that OPG is not proposing to use any portion of the proceeds to offset the increase in test-year payment amounts?
e) How does OPG propose to recover the transaction costs, including all tax implications, related to the sale? If OPG is proposing to recover these costs from ratepayers, please explain the reasons for the approach.

**6.11-Staff-198**
Ref: Exh F3-2-1 Table 2
Ref: Exh F3-2-2
The evidence states that the asset service fee for 700 University has been discontinued and replaced with a lease payment under real estate costs under support services. The evidence also states that 2015 asset service fees are higher than 2014 by $9.6M due to expenses related to the Enterprise System Consolidation Program.

Please explain the high level of asset service fees in the 2016-2019 period vs the 2014 actual asset service fees.

**OTHER REVENUES**

**Nuclear**

**Issue 7.1**
**Are the forecasts of nuclear business non-energy revenues appropriate?**

**7.1-Staff-199**
Ref: Exh G2-1-1 page 4
At the above reference, OPG notes that a change in customer requirements resulted in no Helium-3 sales historically, and none are projected for the future.

Please describe the nature of the changes in customer requirements.

**7.1-Staff-200**
Ref: Exh G2-1-1 page 5
The evidence states that:

> OPG and the IESO negotiated an extension to the existing Reactive Support and Voltage Control Service Agreement effective January 1, 2013 to May 31, 2016. OPG's expectation for the plan period is that the new contract will be negotiated with terms and conditions similar to those in the existing contract; hence the forecast is based on 2015 values with an allowance for inflation.

a) Please confirm if a new contract was negotiated for the period after May 1, 2016.
b) If the answer to (a) is yes, does the re-negotiated contract contain similar terms and conditions as the one previous?

c) If the answer to (a) is no, please provide an explanation of the differences between the service agreements and confirm if the forecasted values remain appropriate?
d) What rate is used as the allowance for inflation?

**7.1-Staff-201**
Ref 1: Exh G2-1-1 page 6
Ref 2: Exh G2-1-1 Table 1
At reference 1, OPG notes that "direct costs for heavy water sales include labour for handling, testing, loading, unloading, and packaging; the cost of containers, and transportation costs. OPG proposes that 50 percent of the related costs from the sale of surplus heavy water continue to be included in the determination of the revenue requirement in accordance with the OEB's decision in EB-2010-0008."

Please confirm that, because there are no sales projected for heavy water after 2017, no direct costs for the sale of heavy water are included in reference 2.

**Bruce Nuclear Generating Station**

**Issue 7.2**
**Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?**

**7.2-Staff-202**
Ref. Exh G2-2-1, page 2 of 21
OPG states that the methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce lease is consistent with what has been used in previous applications, which was independently reviewed and deemed appropriate by Black & Veatch Corporation Inc. as part of EB-2010-0008.

a) What analyses has OPG undertaken since the independent review to support that this methodology continues to be appropriate for purposes of the current application?
b) What is OPG's policy with respect to reviewing and updating this allocation methodology to ensure its continued appropriateness?

**7.2-Staff-203**
Ref. Exh G2-2-1, page 4 of 21
Under the Lease Term section, OPG indicates that the lease has been extended by 21 years from December 31, 2043 to December 31, 2064 such that Bruce Power now has options to renew the lease for additional consecutive renewal periods for up to 46 years after the expiry of the initial lease term on December 31, 2018 (the 2015 Amendment). OPG's test period forecasts assume that Bruce Power will exercise the options to renew the lease.

a) Please provide a copy of the Agreement, or the relevant excerpts from the Agreement, that detail each of the renewal periods available after the expiry of the initial lease term on December 31, 2018.
b) Prior to the 2015 Amendment, the lease term for accounting purposes was assessed to be December 2036, but the actual maximum available term of the lease was to December 2043. Why does the period between 2036-2043 now form part of the lease term for accounting purposes if it didn't qualify previously?
c) The 2015 Amendment extended the maximum lease-term by 21 years. On what basis does this additional renewal period qualify to form part of the lease term for accounting purposes?
d) Why does the updated lease term of 2064 extend beyond the useful life of the longest running Bruce station (Bruce B station, which has an end of life date of 2061)?

**7.2-Staff-204**

Ref. Exh G2-2-1, Section 4.1.2, page 8 of 21

OPG indicates that Supplemental rent revenue is generally recognized on a cash basis for financial accounting purposes because it is not a fixed amount.

a) The 2015 Amendment has eliminated the HOEP triggered provision for a conditional supplemental rent rebate. In light of the new methodology that has been implemented, please indicate why it is still appropriate to recognize the supplemental rent revenue on a cash basis.
b) How would the supplemental rent revenue forecast for the test years be impacted had they been presented on an accrual basis? Please provide a table that compares the current test year forecast of supplemental rent with the annual forecasted amounts under accrual accounting.

**7.2-Staff-205**

Ref Exh G2-2-1, page 12 of 21

In regards to the forecasted number of used fuel bundles for purposes of calculating the test period supplemental rent revenues, OPG indicates that these volume estimates are based on forecasted information submitted by Bruce Power.

a) What process is in place to review and assess the reasonableness and reliability of the assumptions used by Bruce Power in preparing these forecasts? .
b) Does this same forecast form the basis of the estimates for the test year "Used Fuel Storage and Disposal Expenses": since it is driven by used fuel bundle volume as well?
c) Please provide a table that provides the historical actual used fuel bundle volume for 2013-15 and the estimated volume for the bridge and test years.
d) The supplemental rent revenue estimate of $161.2M for 2021 is below the $182M average over the test period. Please explain why.

**7.2-Staff-206**

Ref. G2-2-1, Section 4.1.1, page 7 of 21

This section indicates that pursuant to the 2015 Amendment, the renewal term base rent payments commencing in 2019 are generally intended to cover the executory costs being incurred by OPG in connection with the lease.

a) The evidence states that up to the 2015 Amendment, there has been insufficient evidence to characterize for accounting purposes that a portion of the base rent is intended to cover executory costs. Please indicate what has changed that now allows for this distinction. Please provide the relevant excerpts from the 2015 Amendment.
b) Please provide a table that compares the test year base rent revenues as currently presented in this application, versus the quanta had there been no executory cost component.

**NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES**

**Issue 8.1**
**Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?**

**Issue 8.2**
**Is the revenue requirement impact of the nuclear liabilities appropriately determined?**

**8.2-Staff-207**
Ref: Exh C2-1-1, page 5
OPG has indicated that the December 31, 2015 tranche was calculated using an accounting discount rate of 3.21 per cent, which is also then used to calculate the annual accretion expense for the tranche.

a) Please indicate how this rate was derived, making reference to the source of the rate or the source of each component of the total rate.
b) Was there an acceptable range of rates that was contemplated prior to the final rate selection?
    i. If so, please provide the low and high end of this range, and please indicate why management determined that the rate selected was most appropriate.
    ii. Based on the range provided above, could the calculation of the test period return on ARC (prescribed facilities) or accretion expense (for both the Bruce and prescribed facilities) be materially impacted had either of the other rates under consideration been used? Provide estimates as to how much.
c) Was there any change to the methodology or assumptions used by management compared to what was used in determining the discount rates for the previous five tranches? Please provide explanation for any change.

**8.2-Staff-208**
Ref: Exh C2-1-1, page 15 of 15

OPG indicates that the proposed period revenue requirement reflects the approved 2012 ONFA Reference Plan. The corresponding revenue requirement impact of the approved 2017 Reference Plan will be recorded in the Nuclear Liability Deferral Account for the prescribed facilities and the Bruce Lease Net Revenue Variance Account for the Bruce facilities.

a) Using the latest draft of the 2017-2021 ONFA Reference Plan, please provide a table that summarizes the estimated revenue requirement impact on the prescribed facilities as well as on the Bruce Net Revenues.
b) Has the reference plan update been finalized for the Province's approval? Based on the process for previous reference plans, has provincial review significantly affected the reference plan?
c) Please identify any limitations to using the draft 2017-2021 reference plan to underpin the payment amounts in the current proceeding.

## DEFERRAL AND VARIANCE ACCOUNTS

### Issue 9.1
### Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

**9.1-Staff-209**
Ref: Exh H1-1-1a, Table 1a and Table 8
Opening balances of the Pension & OPEB Cash Versus Accrual Differential Deferral and Pension & OPEB Cash Payment Variance Accounts for Hydroelectric and Nuclear are presented in Table 1a. These balances were presented in the EB-2014-0170 evidence, however, no further information regarding the balances were provided in that application as the balances were not proposed for disposition. OPG is proposing the Pension & OPEB Cash Payment Variance Account for disposition in this proceeding. OPG is not proposing the Pension & OPEB Cash Versus Accrual Differential Deferral Account for disposition, but OPG has proposed that the future recovery of this account be limited to the outcome of the generic consultation and not be subject to a future prudence review.

Please provide the derivation of the 2014 opening balances similar to that as in Table 8.

**9.1-Staff-210**
Ref: Exh H1-1-1, Table 11 and 11a
Ref: Exh D2-2-10, Table 5
In the table referenced above the balance of the Capacity Refurbishment Variance Account (CRVA) for DRP is shown as $41.6M-$12.4 = ($10.9M) for non-capital and ($37.5M) for capital, for a total of ($48.2M).

a) Please confirm that the above numbers are correct.
b) Please provide an explanation for the variance between forecast and actual non-capital amounts.

c) Complete the following table with actual additions to rate base for 2014 and 2015:
d) Please reconcile the Net Plant Rate Base Amounts of $116M and $204.6M with the actual in-service capital additions of $43.5M and $147.1M shown in the second reference above.

| $M | **2014 Forecast** | **2014 Actual** | **2015 Forecast** | **2015 Actual** |
|---|---|---|---|---|
| Darlington Energy Complex | 92.0 | | 89.6 | |
| Water and Sewer Project | 20.8 | | 26.4 | |
| Heavy Water Storage & Drum Handling Facility | | | 20.3 | |
| Darlington Operations Support Building Refurbishment | | | 14.6 | |
| Auxiliary Heating System | | | 17.9 | |
| Electric Power Distribution System | 2.2 | | 7.3 | |
| Powerhouse Steam Venting System | | | 5.0 | |
| Third Emergency Power Generator Project | | | 16.0 | |
| Other Miscellaneous Projects | 1.0 | | 7.5 | |
| Any other projects? | | | | |
| Net Plant Rate Base Amount | 116.0 | | 204.6 | |

**9.1-Staff-211**
Ref: H1-T1-S1, page 26
In accordance with EB-2014-0370 payment amounts order, no interest is applied to the sub-accounts of Bruce Lease Net Revenues Variance Account. OPG proposes that the interest on the Non-Derivative Sub-account resume as of the effective date of the payment amounts order in this application.

Please explain why OPG proposes that interest resume.

**Issue 9.2**
**Are the methodologies for recording costs in the deferral and variance accounts appropriate?**

**9.2-Staff-212**
Ref: Exh H1-1-1, page 6
For the deviations pertaining to newly regulated hydroelectric facilities in the Hydroelectric Water Conditions Variance Account, the corresponding monthly forecasts for January 1 to June 30, 2015 underpinning EB-2013-0321 payment amounts were used and the corresponding average monthly forecasts for 2014 and 2015 underpinning the EB-2013-0321 payment amounts were used. OPG proposes that this method be used to calculate deviations in energy projection after 2015 continue to be used.

a) Please clarify the corresponding years and forecast basis (i.e. monthly forecast or average monthly forecasts) that is proposed to be used to determine deviations from the effective date of the payment amounts order in this proceeding.

b) Please explain OPG's proposed forecast basis.

**9.2-Staff-213**

Ref: Exh H1-1-1 pages 3-21

OPG proposes that reference amounts used to determine post-2015 hydroelectric additions to Ancillary Services Net Revenue Variance Account, Income and Other Taxes Variance Account, the Pension & OPEB Cash Payment Variance Account and Capacity Refurbishment Variance Account be the forecasts underpinning the hydroelectric payment amounts in 2014 and 2015 approved in EB-2013-0321. Additions to these accounts are based on revenues, OM&A or some element of revenue requirement.

a) For each of the accounts, please explain why OPG is proposing to use the monthly reference amounts established in the EB-2013-0321 proceeding even though payment amounts recovered will be updated through the Hydroelectric IRM proceeding.
b) Under the hydroelectric IRM price cap proposal, payment amounts are adjusted annually by the price cap formula, with the adjustment to reflect the (I-X) inflation in underlying costs. Furthermore, the price cap adjustments are multiplicative over time. Under OPG's proposal, the variance between actuals over 2017-21 and the average monthly amounts as approved for 2014-15 in EB-2013-0321 will continue to increase.

   Using the Income and Other Taxes Variance Account as an example, why should the reference amount not be the monthly average of the 2014-15 income tax provision as approved in EB-2013-0321 multiplied by the product of the price cap adjustments to each year, reflecting the implicit inflationary increase in the tax provision?
c) Implicitly, for the nuclear payments side, the production forecast also factors into the determination of the reference amount as the revenue requirement reflects the costs which depend explicitly on the production forecast.

   A production forecast for hydroelectric generation is not explicitly required as the payments are a unitized recovery of the revenue requirement and the proposed price cap adjustment accounts for the main two drivers of costs – inflation and productivity – while it is assumed that changes in production (if growth) increases costs in an aggregate sense but also increases revenues so that, all else being equal, rates (payments) remain compensatory, even if costs (including taxes) change due to changes in production.

   A closer approximation to the nuclear tax payment would be to account for both the price cap adjustment and the changes in production relative to the 2014-15 base amount as approved in EB-2013-0321. Please provide OPG's views with respect to an adjustment for productivity to the monthly reference amounts.

**Issue 9.3**
**Are the balances for recovery in each of the deferral and variance accounts appropriate?**

**9.3-Staff-214**
Ref: Exh H1-1-1, page 9 and Table 4
There were no additions into the Hydroelectric Incentive Mechanism (HIM) Account in 2015 as actual HIM revenues were significantly below the specified threshold of $58M.

Please explain why HIM revenues were significantly below the threshold.

**Issue 9.4**
**Are the proposed disposition amounts appropriate?**

**Issue 9.5**
**Is the disposition methodology appropriate?**

**9.5-Staff-215**
Ref: Exh H1-2-1
Ref: Exh A1-3-1 page 10
OPG is requesting recovery of the audited 2015 year end balances (less 2016 amortization amounts approved in EB-2014-0370) in certain deferral and variance accounts. OPG proposes payment amount riders for the period January 1, 2017 to December 31, 2018.

a) Please explain why OPG has selected a two year disposition period.
b) As noted in Exh A1-3-1, the forecast bill impact in 2017 is a decrease of $1.29 per month. Please determine the bill impacts in 2017 to 2021 if a one year disposition period is used.
c) In the deferral and variance account application, EB-2012-0002, the approved settlement proposal resulted in payment amount riders for two years, but the collection in the first year was 60% of the account balances. Please determine the bill impacts in 2017 to 2021 if 60% of the account balances underpin the 2017 payment amount riders.

**Issue 9.6**
**Is the proposed continuation of deferral and variance accounts appropriate?**

**Issue 9.7**
**Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?**

**Issue 9.8**
**Should any newly proposed deferral and variance accounts be approved by the OEB?**

**9.8-Staff-216**
Ref: Exh: H1-1-1, pages 31-32
For the Nuclear ROE Variance Account,

a) Please explain how the proposed account would meet the materiality criteria.
b) Please perform a sensitivity analysis on impact to this account, if the ROE was to change by 1% (increase and decrease).

**9.8-Staff-217**
Ref: Exh: H1-1-1, pages 32-33
Please calculate the approximate amounts that would be recorded in the proposed Hydroelectric Capital Structure Variance Account if the OEB approves a capital structure of 49% equity and 51% debt in this application.

**9.8-Staff-218**
Ref: H1-1-1, pages 29-33
Please provide a draft accounting order for the four new deferral and variance accounts that OPG proposes to be established in this application.

**REPORTING AND RECORD KEEPING REQUIREMENTS**

**Issue 10.1**
**Are the proposed reporting and record keeping requirements appropriate?**

**Issue 10.2**
**Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?**

**10.2-Staff-219**
Ref: Exh A1-3-2 Chart 11
Ref: EB-2013-0321 Decision page 17
OPG proposes to file safety, reliability and cost effectiveness performance measures for the regulated hydroelectric facilities annually. OPG states that these are the four measures under the same key performance areas were filed in the previous payment amounts proceeding, EB-2013-0321.

The proposed cost effectiveness measure is OM&A Unit Energy Cost ($/MWh). In the EB-2013-0321 decision, the OEB found OPG's hydroelectric benchmarking to be inadequate, commenting that only base OM&A was considered, which is only 50% of total OM&A expenses.

Please confirm whether the proposed cost effectiveness measure is base OM&A only. If yes, please explain why this measure is appropriate in light of the EB-2013-0321 decision.

**10.2-Staff-220**

Ref: Exh A1-3-2 Chart 11
Ref: Exh A2-2-1 Attachment 1 page 34
Ref: Exh A1-3-2 Attachment 2 page 10

a) On page 34 of Attachment 1 to Exh A2-2-1 (OPG business plan), the operational targets for Hydro Thermal Operations, designed to drive continuous performance, are set out. Why has OPG proposed to report only a few of these measures, and in some cases different measures, e.g. the business plan reports Total Hydroelectric Generating Cost per MWh?
b) The Total Hydroelectric Generating Cost per MWh, as reported in the business plan, would include regulated and non-regulated hydroelectric facilities. Does OPG track Total Hydroelectric Generating Cost per MWh for the regulated hydroelectric facilities? If so, please explain why OPG has proposed annual reporting on OM&A Unit Energy Cost.
c) On page 10 of Attachment 2 to Exh A1-3-2, the functions that Navigant used to benchmark the cost OPG's regulated hydroelectric facilities are summarized. Why has OPG proposed to report only OM&A Unit Energy Cost and not some/all of the cost performance measures used by Navigant?

**Issue 10.3**

**10.3 Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?**

**10.3-Staff-221**

Ref: Exh A1-3-2 Chart 12

OPG proposes to report the key performance measures that are used in its annual nuclear benchmarking report.

a) The 2015 nuclear benchmarking report on 2014 performance is dated November 2015. The 2016-2018 business plan, which lists some of the 2015 actual nuclear performance measures is dated May 2016. When will the 2016 nuclear benchmarking report on 2015 performance be completed?
b) Will the proposed annual report include best quartile and median information for peers?
c) Will the proposed annual report include actual data for the year as well as rolling averages?
d) Will the proposed annual report only provide the results for Darlington and Pickering separately or will there be some measures reported for OPG?

**Issue 10.4**

**Is the proposed reporting for the Darlington Refurbishment Program appropriate?**

**10.4-Staff-222**

Ref: Exh A2-1-1, Attachment 3, page 100
Ref: Exh D2-2-2, page 8

The first reference above provides a list of members of the Darlington Refurbishment Committee and the second reference refers to the Refurbishment Construction Review Board and the Ministry of Energy's oversight.

a) Please provide details if there have been any changes to the makeup of the Darlington Refurbishment Committee.
b) Provide a copy of the charter or any other governance documents regarding the creation and scope of responsibility of the Darlington Refurbishment Committee.
c) Who are the members of the Refurbishment Construction Review Board? Please provide names and resumes.
d) Provide a copy of the Refurbishment Construction Review Board's charter or any other governance documents regarding the creation, purpose, scope of responsibility, and role during the execution phase of the DRP.
e) Please provide details of the frequency and type of reporting that the Darlington Refurbishment Committee and the Refurbishment Construction Review Committee will receive.
f) In addition to the oversight being provided by the Darlington Refurbishment Committee and the Refurbishment Construction Review Committee, please provide details of the oversight that is being provided by the Government of Ontario? For example, what is the reporting frequency and how actively involved will the government's team be in the ongoing monitoring of the program's process?

**10.4-Staff-223**
Ref: D2-2-9 page 8 and 9
OPG plans to issue annual status reports to the public for the duration of the DRP through its website.

a) When does OPG plan to issue the first report through its website?
b) Other than the website report, how will OPG report on the project status to the OEB and other interested parties? Explain the format, content and frequency of external reporting for earned value, budget status, safety and project status.
c) Explain the format, content and frequency of internal reporting for earned value, budget status, safety and project status.

**METHODOLOGIES FOR SETTING PAYMENT AMOUNTS**

**Hydroelectric**

**Issue 11.1**
**Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?**

**11.1-Staff-224**
Ref: Exh A1-3-2 page 5
At page 5, OPG states that:

> [it] proposes a price-cap index rate-making methodology for the company's regulated hydroelectric generation assets, modelled closely on 4GIRM method set out in the RRFE. Of the three rate-making methods in the RRFE, OPG believes that a price-cap index is best suited to the circumstances of the company's hydroelectric generation facilities.

Is OPG saying that a mechanism like 4GIRM will typically make sense for the Company going forward or is its comment limited to the next five years?

**11.1-Staff-225**
Ref: Exh A1-3-2 pages 8-9
OPG states that

> With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities...
>
> Notwithstanding the negative productivity factor identified by the LEI TFP study, OPG is proposing a productivity factor of zero...
>
> Although LEI's TFP study concludes that a -1% productivity factor is appropriate for OPG's regulated hydroelectric facilities, OPG recognizes that the OEB has declined to accept a negative productivity factor in the context of electricity distribution. OPG therefore proposes a 0% productivity factor for the 2017-2021 IR period. This increase to the productivity factor essentially creates an additional 1% stretch factor for OPG's hydroelectric facilities during each year of the IR period, relative to the industry trend identified in the TFP study.

a) In the aftermath of recent high capex that includes the Niagara Tunnel Project, why shouldn't OPG's hydroelectric operations be poised for unusually slow cost growth?
b) Couldn't this give rise to *superior* productivity growth and not just industry *average* growth?
c) Does LEI's physical asset approach to productivity measurement recognize this kind of productivity surge?
d) Is LEI's study designed to capture the productivity trend of a utility that has just concluded capex surge? If not, how can the difference between -1% and 0 be deemed an additional stretch factor?
e) Does LEI employ a method for measuring capital quantity growth that would cause it to slow after a recent capex surge?

**11.1-Staff-226**
Ref: Exh A1-3-2 pages 9, 20-22
At page 9, OPG states:

> Total cost benchmarking is an important component of each rate-setting model in the RRFE and plays an important role in OPG's proposed IR frameworks for both hydroelectric and nuclear assets. Under the 4GIRM method, in which OPG's hydroelectric IR proposal is based upon, an applicant's benchmark performance is used to determine the stretch factor in the distributor's price-cap index. Similarly, OPG proposes that the hydroelectric stretch factor be determined based on the hydroelectric total cost benchmarking study conducted by Navigant Energy Consulting Inc. ("Navigant"), which is filed as Attachment 2 to this schedule.

At page 20, OPG states that "Navigant benchmarked approximately 92% of OPG's 2013 costs attributable to its regulated hydroelectric operations against a peer group".

At pages 21-22, OPG states that:

> Navigant identified Partial Function Cost as the key cost metric for benchmarking purposes to assess OPG's relative performance to its peers... OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost.

a) Please confirm that for 4GIRM the OEB uses an *econometric* model of *total* cost to perform benchmarking exercises. Total cost includes the cost of all plant and not just capital expenditures. Total cost would thus be unusually high in the aftermath of a capex surge.
b) In what sense then can the Navigant study be deemed a total cost benchmarking study? Does the study effectively address OPG's recent hydroelectric capex surge?
c) Please explain the basis for the statement that the Navigant study addressed 92% of OPG's cost.
d) Approximately what percentage of OPG's total hydroelectric cost (excluding water fees) is its proposed stretch factor actually based on?

**11.1-Staff-227**

<u>Ref: Exh A1-3-2 pages 12-15</u>

In section 2.3.1, OPG documents the methodology for its proposed inflation factor. The inflation measure, or Input Price Index ($IPI_{OPG}$), uses that same data and formulation as the $IPI_{dx}$ used for the current electricity distributor Price Cap IR and Annual Index IR plans, and only differs in having differing weights for labour (12% for OPG based on hydroelectric generation industry statistics versus 30% for electricity distributors) and non-labour (88% for OPG versus 70% for electricity distributors). OPG has calculated a preliminary $IPI_{OPG}$ (annual percentage change) of 1.8% based on March 2016 StatsCan data. OPG proposes that it would file an annual hydroelectric IRM payment amounts adjustment application in each year and that the "payment amounts adjustment would be based on the values for the GDP-IPI (FDD) and Ontario AWE at the time of those applications."

a) The OEB currently calculates and posts the $IPI_{dx}$ and the derivation of it based on StatsCan's publication of Q2 national account data, as being the most current information available in time for the processing of IRM rate adjustment applications for January 1 of the following year. To ensure consistency of the data on which OPG's inflation index is based with that used for electricity distributors, the OEB could calculate and post the $IPI_{OPG}$ and $IPI_{dx}$ in early September of each year. Please confirm that this timing is acceptable or explain why not.

b) Based on the 2016 Q2 National Accounts data released by Statistics Canada on August 31, 2016, which data are being used by the OEB to calculate the IPI for 2017 electricity distribution IRM rate adjustments, OEB staff has calculated the $IPI_{OPG}$ for 2017, as proposed by OPG, to be 1.7%, This change reflects routine data revisions in the published StatsCan data. Please confirm this updated IPI based on OPG's proposed methodology. In the alternative, please explain.

| Inputs and Assumptions | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Non-Labour GDP-IPI (FDD) - National | | | | | | | Labour AWE - All Employees - Ontario | | | Annual Growth for the 2-factor IPI based on OPG's proposed weights | |
| | Q1 | Q2 | Q3 | Q4 | Annual | Annual % Change | Weight | Annual | Annual % Change | Weight | Annual | Annual % Change |
| **2014** | 112.5 | 113.2 | 113.7 | 114.1 | 113.375 | | | $ 938.27 | | | 103.7 | |
| **2015** | 114.4 | 114.8 | 115.6 | 116.1 | 115.225 | **1.6%** | **88%** | $ 962.73 | **2.6%** | **12%** | **105.5** | **1.7%** |

**Sources:**

- GDP-IPI (FDD): Statistics Canada, Table 380-0066 - Price Indexes, gross domestic product, quarterly (2007 = 100 unless otherwise noted) - 2016 Q2, issued August 31, 2016
- Average Weekly Earnings (AWE): Statistics Canada, Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Clasification Classification System (NAICS), annual (current dollars)

Data accessed August 31, 2016

**11.1-Staff-228**

Ref: Exh A1-3-2 page 22

Ref: *Report of the Board: New Policy Options for the Funding of Capital Investments* (EB-2014-0219), issued September 18, 2014

Ref: *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 24, 2016.

In section 2.4, OPG states that it would be eligible to apply for an Incremental Capital Module (ICM) for qualifying hydroelectric projects. OPG states that any such request would be prepared in accordance with OEB policy, and refers to the *Report of the Board: New Policy Options for the Funding of Capital Investments* (EB-2014-0219), issued September 18, 2014 (the ACM Report).

On January 24, 2016, the OEB issued its *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219). This Supplemental Report clarified and revised certain matters, including revising the methodology and the formula for the materiality threshold.

Please explain any differences from the current ACM/ICM policy applicable to electricity distributors that OPG proposes for any ICM or ACM treatment for its prescribed hydroelectric generation assets, if its proposal is approved by the OEB.

**11.1-Staff-229**

Ref: Exh A1-3-2 pages 20-22

In section 2.3.3.2, OPG documents its proposed stretch factor of 0.3, which corresponds to the middle (median) stretch factor used for electricity distribution rate adjustments under the current 4$^{th}$ Generation IRM (Price Cap IR) plan. OPG states that its proposal is based on the independent benchmarking study conducted by Navigant, which is provided in Exh A1-3-2 Attachment 2.

OPG states that:

> OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost. Navigant found that OPG's regulated hydroelectric facilities are effectively at the median for the hydroelectric generation industry on this measure. Using the range of stretch factors applied in the 4GIRM method, OPG's performance should result in a 0.3% stretch factor.

a) As noted by OPG, the Navigant study uses a Partial Function Cost benchmarking. The LEI study (Exh A1-3-2 Attachment 1) is a Total Factor Productivity study, and the price cap rate adjustment methodology is also inherently to address all costs of production not addressed by deferral and variance accounts. Please explain why the Navigant benchmarking study, being a "partial function cost benchmarking" study, is an appropriate basis for a stretch factor.
b) Chart 6 summarizes the differences between OPG's hydroelectric generation assets versus those of the sample that Navigant benchmarked OPG against, with respect to characteristics such as median age, median group size and median unit size (the latter two in terms of generation size (MW)). Chart 6 demonstrates that OPG's characteristics differ markedly from those of the median for the benchmarking group. Based on these differences, please provide further explanation as to why OPG concludes that the median stretch factor is reasonable.
c) What alternative approaches or analyses did OPG conduct (or have conducted) in considering what would be a reasonable stretch factor or consumer productivity dividend?

**11.1-Staff-230**

Ref: Exh A1-3-2 pages 9, 20-22

Ref: Exh A1-3-2 Attachment 2

OPG describes its rationale for proposing the stretch factor of 0.3%. In large part, it uses the general findings of the Navigant hydroelectric benchmarking study (Exh A1-3-2 Attachment 2) that OPG is generally in the median of its comparator group as supporting the choice of the middle or median, with the 0.3% being the OEB's determined stretch factor for the middle cohort for electricity distributors.

As is noted in footnote 1 on page 3 of the Navigant study, the Navigant benchmarking compared OPG's performance relative to the comparator group for one year (2013) only.

One year's worth of performance data may be volatile, particularly with respect to hydroelectric generation assets, which are more capital-intensive and often longer-lived than even for other capital-intensive industries, including network-based industries such as telecommunications and electricity distribution. Capital investments can be particularly "lumpy", where a major investment in a short period of time may obviate significant capital investments in the future and facilitate significant operating efficiencies in subsequent years. Comparing performance between different utilities may not necessarily be "apples-to-apples" depending on where each utility is on the investment and life cycle of its own assets.

a) What information does OPG have on its performance relative to a comparator group of hydroelectric generators for a longer period? If it has such data, please provide any such studies or, at a minimum, a summary of the results for each such available study.
b) OPG has not proposed that the stretch factor be updated annually, as is done for Ontario's electricity distributors since 3rd Generation IRM was implemented in 2009, but that the stretch factor be fixed for five-year term of the hydroelectric IRM plan.
    i. Please explain why annual benchmarking to update the stretch factor has not been proposed as part of the hydroelectric IRM plan.
    ii. If benchmarking were to be done annually to update the stretch factor, certain checks and balances would be needed to ensure the integrity and objectivity of such benchmarking analysis. This could include oversight by the OEB, or external auditability of the methodology and results.

        Please provide OPG's views on what changes would be needed in conducting of an annual benchmarking analysis, or in the reporting, oversight and review of any such study, to facilitate the use of such an annual benchmarking study to update the stretch factor for each annual price cap adjustment.

**11.1-Staff-231**

<u>Ref: Exh A1-3-2 pages 6-7, 22-23</u>
<u>Ref: Exh H1-1-1</u>
In section 2.6, OPG indicates that:

> OPG will continue to report the balances in its deferral and variance accounts as directed by the OEB in EB-2010-0008. OPG intends to monitor these

balances and may make an application to dispose of these account balances during the 2017-2021 period.

a) What criteria will OPG use to determine whether to make an application to dispose of DVA accounts during the 2017-2021 period?
b) Please identify which DVAs OPG foresees will be reported on, but for which disposition is not expected to occur during the term (2017-2021) of the hydroelectric IRM plan.

**11.1-Staff-232**

Ref: Exh A1-3-2

The current application is the first generation IRM plan for OPG's regulated hydroelectric generation assets. Reviews on how plans have performed have formed a significant part of the development of 2$^{nd}$ generation and subsequent IRM plans for both electricity and natural gas distributors as regulated by the OEB.

a) While it is premature at this point to deal with specifics, does OPG concur with the concept of having a review towards the end of the current plan (i.e., during 2020 or 2021)? Please explain the response.
b) Please provide any views that OPG has at this point regarding the potential or likely issues, nature or scope of any such review.

**11.1-Staff-233**

Ref: Exh A1-3-2 Attachment 1 page 8

The LEI report states: "Because an industry TFP study reports historical productivity growth rates, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically."

a) Please provide evidence that the future business conditions of OPG are similar to those experienced by the companies LEI used to calculate the productivity trend over the 2002-2014 period.
b) Are the productivity trends for very-long lived and mature assets sensitive to the replacement capex undertaken during the sample period?
c) Will the large replacement and upgrade investments made by OPG in recent years slow its cost growth in the next ten years? If so, should this affect the choice of a sample period?
d) How much capital replacement must take place for a "mature" asset to no longer be considered "mature" (i.e. if hypothetically everything was repaired/replaced, is the plant now "new" with all the expectations of a new plant)?
e) If it were possible, would a time period that captures a greater portion of the life cycle such as one starting in the 1970s or 1960s be more representative of future expectations?

**11.1-Staff-234**

Ref: Exh A1-3-2 Attachment 1, pages 7 and 18

This evidence is the updated TFP study conducted by LEI based on OPG and a selected sample of US utilities with significant hydroelectric generation.

Footnote 5 on page 7 of LEI's report states:

> LEI notes that there is no precedent for TFP studies of hydroelectric generation businesses for purposes of regulatory ratemaking. This is not surprising as generation is not typically regulated using IRM. However, TFP based empirical studies do exist for generation in academia.

On page 18, LEI states:

> After considering 18 productivity studies on generation, conducted both for academic and regulatory purposes, LEI found that generation was the most common metric chosen for measuring output. [28]

Footnote 28 refers to section 9.1.3.1 of Appendix B of the LEI report but insufficient additional information is provided there.

a) Please provide a list of generation TFP studies of which LEI and/or OPG are aware.
b) Please describe how these other studies informed LEI in conducting its documented TFP study for OPG.
c) What are the results, in terms of TFP for hydroelectric generation, from these other studies? How were these results from other studies used to inform LEI and/or OPG regarding the reasonableness of the observed result of about -1% TFP from LEI's study?

**11.1-Staff-235**
<u>Ref: Exh A1-3-2 Attachment 1, page 18</u>
LEI states that:

> [it] determined that it would be best to use a single output of generation measured in MWh... after considering 18 productivity studies on generation...LEI found that generation was the most common metric chosen for measuring output. Generation is the appropriate output because it is the essential output being produced by every power generator. Further, generation data is readily available, and is generally measured consistently across power plants and firms.

a) Please provide a table listing the output and capital input quantity specifications and datasets of each of the 18 studies referred to above.
b) Please confirm that generation capacity is also sold in many bulk power markets.
c) Which has a larger impact on generation cost: changes in MWh or changes in capacity? Please explain and support your response.
d) Are pumped storage volumes included in the output measure? If not, why not?

**11.1-Staff-236**

Ref: Exh A1-3-2 Attachment 1 pages 16-17

On pages 16 and 17 of its study, LEI states:

> LEI believes that the thirteen year timeframe of 2002-2014 is appropriate for this study. For OPG, 2002 is also the year the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. US electricity markets also went through reforms and restructuring phases in the late 1990s and early 2000s. The thirteen year study period balances the high variability of year-on-year trends but is also not so long term as to capture "stale" industry trends that would not repeat themselves in the future.

a) In general, as is exemplified by Chart 6 on page 20 of Exh A1-3-2, hydroelectric generation assets have significantly long economic lives, which range into several decades. Some of OPG's hydroelectric generation assets are over a century old, even if they have been refurbished and modernized over time. Is the 12 year study period a sufficiently long slice of the normal useful lives or the business cycle for investment and operations of such-long lived assets so as to give a representative picture?
b) Should the sample period for a TFP study be longer to the extent that output is volatile?
c) What are examples of the '"stale" industry trends that would not repeat themselves in the future' that LEI alludes to in the above quote?

**11.1-Staff-237**

Ref: Exh A1-3-2 Attachment 1, pages 19, 41-42

At page 19 of its report, LEI states that:

> LEI recognizes that the generation output metric is dependent on hydrology and system operations. However, the longer-term nature (thirteen years) of the TFP study compensates for the year-on-year variability in annual generation, and therefore LEI believes variability in annual hydrology should not be an obstacle to this TFP study.
>
> Using OPG as an example, the average of water flows during the period 2002-2014 is within 1% of the twenty year average (1994-2013).

At pages 42-42 of its report, LEI states:

> average growth rate for capital inputs measured in MW was 0.15% over the 2002- 2014 period, with little year over year fluctuations. This result is to be expected for a mature hydroelectric industry as construction of new generation facilities is infrequent.... For output, net generation growth rate was on average -0.64% for the industry.[67] Note year over year fluctuations were much more visible compared to the average, which is to be expected due to varying hydrology cycles during the 2002-2014 period, as well as

> other factors such as changes in demand and surplus baseload generation conditions.
>
> [67]A negative generation growth rate does not imply the same capital is producing less over time, but rather is related to the hydrology cycles at the start and end years of the study.

a) Please explain the decline in the MWh generated by sampled utilities relative to their generation capacity during the sample period.
b) What grounds are there to support that this trend will continue?
c) Was the trend in MWh generated adjusted for changes in hydrological conditions during the sample period?
d) What are the expected volume/capacity and water flow trends of OPG in the next five years and the following five years?
e) Is the volume/capacity trend of the sampled utilities pertinent to an X-factor for OPG?
f) Can footnote 67 be taken to mean that hydrological conditions are the cause of declines in capital productivity in the study?
g) If the generation growth rate is not related to production over time, then why was generation selected as the measure of output quantity?
h) For a given unit whose availability and capacity does not change, would the measured capital productivity be zero, by definition, under normal hydrological conditions using the LEI methodology?

**11.1-Staff-238**
<u>Ref: Exh A1-3-2 Attachment 1, page 20</u>
LEI states that:

> the most common input observed for generation-related productivity studies was capacity as a physical measure of output. Capital can also be measured using replacement cost, but this is much less common - in fact, nearly every generation related TFP study used capacity as a measure of capital.

a) Please confirm that data availability is a major reason why the monetary method for measuring the capital quantity has not been used in other studies.
b) Please confirm that the required capital cost data are available to calculate capital costs and quantities using the monetary method for investor-owned US electric utilities.
c) Please cite examples where the physical assets approach to capital quantity measurement has been used to measure productivity trends by any of the following:
    - U.S. or Canada by National Statistical Agencies such as Statistics Canada, Bureau of Labor Statistics.
    - In productivity studies approved by regulators for the setting of productivity factors used in regulation.

**11.1-Staff-239**
<u>Ref: Exh A1-3-2 Attachment 1, page 20</u>

On page 20 of its study, regarding measures of output to be used for the TFP analysis, LEI states:

> Other services, such as sales of ancillary services, or water management for flood control and recreational use, are difficult to represent in a TFP study because they lack consistent and easily measurable data; therefore, they should be considered qualitatively only.

There does not appear to be any other discussion in LEI's study of whether or how it considered these other outputs of hydroelectric generation.

Please provide further explanation of how LEI took these outputs, for both OPG and for other generation utilities in the sample, into account, even qualitatively, in conducting the TFP analysis. If these other outputs played no further role, even qualitatively, please explain.

**11.1-Staff-240**
Ref: Exh A1-3-2 Attachment 1 pages 27-28
LEI states in its study that:

> When selecting peers in order to construct an industry group, LEI used a multi-dimensional criteria set, which focused on comparability across peer hydroelectric operations, while keeping in mind issues related to data availability. As a general rule, LEI looked for firms that have a hydroelectric fleet with a total capacity of between 500-1,000 MW (medium size) or more than 1,000 MW (large size). Additionally, a peer needed to have more than one plant, and ideally the average age of a peer's hydro fleet would be around the average age for OPG's prescribed hydro fleet.

a) Why was operating scale accorded such importance when output growth is so slow for the sampled utilities?
b) What definition of system age was used? Please provide the age data for all utilities considered. What companies were excluded from the sample on the basis of the age criterion?
c) Did LEI gather data and/or calculate productivity results for companies other than those included in the final report? If so, please include these results and data.

**11.1-Staff-241**
Ref: Exh A1-3-2 Attachment 1 page 27
LEI states that:

> The start year of 2002 was chosen because it was the first year that full datasets could be constructed across the peer group.[40] As well, the opening of the Ontario competitive market occurred in 2002 which impacted the business environment for OPG; similarly, market restructurings were occurring across parts of the US in the late 1990s and early 2000s.

> [40]Most peers did not have full datasets available before 2002, including OPG, which had revenue data only available starting mid-2002 after market opening

a) Before 2002, did OPG, or its predecessor Ontario Hydro, lack data for hydroelectric generation volume or only for the associated revenue?
b) Please explain how power market restructurings affected the hydroelectric operations of the sampled US electric utilities.
c) What data constraints were encountered for an earlier start date for investor-owned US electric utilities?
d) Is it LEI's view that OPG must be part of the peer group used to calculate its X factor?

**11.1-Staff-242**
Ref: Exh A1-3-2 Attachment 1, page 39
LEI states:

> When estimating individual TFP results, the difference in currencies does not affect results, as a simple scaling up or down of O&M and revenue would result in the exact same outcome. However, in the case of calculating industry TFP trends, Canadian and US figures are compared, and using nonadjusted figures can lead to biases (albeit small) in the TFP results.

Please clarify how the trends for individual utilities were averaged.

**11.1-Staff-243**
Ref: Exh A1-3-2 Attachment 1, page 40
LEI States: "the Two Inputs are Capital measured as Capacity (MW) and Non-capital costs measured as total O&M inputs in constant prices..." and "the Labour share of O&M is 63% and the Non-labour share of O&M is 37%"

a) What companies in the sample did not have itemized data on labour expenses?
b) Did the O&M expense data include only salaries and wages or did it also include pension and other benefit expenses?
c) Please report the exact labour price indexes employed in the study. Do these indexes address labour price trends inclusive of pension and benefit expenses?
d) Please describe the EUCG dataset and explain how it was used to calculate the 63% labour cost share. What is this percentage for OPG? Why was a fixed weight used instead of a time-varying weight?
e) Please explain the rationale for combining the US and Canadian O&M price indexes into a North American O&M price index. How was it used? Please clarify how the 22% weight for Canada was determined.

**11.1-Staff-244**
Ref: Exh A1-3-2 Attachment 1 pages 44 and 59
As stated in its report at page 44, LEI believes that negative TFP trends can be "expected" for mature hydroelectric businesses, because of the fixed production

capability, fixed capital stock and rising costs of maintenance through the life cycle of a hydroelectric resource. As discussed earlier in Section 3.1 of its report, common drivers of productivity include technological innovation and improved economies of scale. However, for a mature hydroelectric business, great leaps forward in technology are extremely rare and economies of scale are generally fixed as soon as the asset is built and put into operation (although occasionally, refurbishments and other capital programs can increase energy production due to advances in new equipment). In general, it should be expected that output levels would be stable over time;[69] capital inputs are constant (once a hydroelectric plant is put into service); and OM&A would likely be increasing over time (in order to maintain asset operational capability as the asset ages).

At page 59, LEI states that:

> The perceived advantage of the monetary method is that it can include capital equipment of all kinds. Some practitioners also argue that the monetary method, with respect to some asset types, produces an estimate that reflects the quality of capital better... Electricity generation assets tend to have long lives and produce a relatively constant flow of services over their useful lives (provided they are properly maintained). As a result, assumptions of declining balance or straight line depreciation are unlikely to properly reflect the true physical depreciation profile of these assets, which are more likely to exhibit a 'one horse shay' depreciation profile.

a) Please confirm that, over the life cycle of a hydroelectric generating station, total cost falls substantially due to depreciation, and such cost reductions can be captured with a monetary method but not the physical assets method.
b) Please confirm that substantial productivity gains are possible when hydroelectric assets are replaced, and that these gains can be captured with a monetary method but not the physical assets method.
c) Please confirm that, in general, when generation capacity is used as the capital quantity index, changes in the productivity (e.g. real cost per unit of capacity) with which the utility provides capacity are ignored in productivity calculations.
d) Please reconcile the statement that an asset provides "a relatively constant flow of services" with the statement that OM&A expenses associated with a hydroelectric generating facility tend to rise as it ages?
e) Please provide three examples of how O&M expenses tend to rise as hydroelectric assets age.
f) Does growth in O&M expenses tend to fall when assets are replaced/modernized?

**11.1-Staff-245**

<u>Ref: Exh A1-3-2 Attachment 1 page 59</u>

LEI States: "Furthermore, the monetary approach requires data going back many years, which would be difficult to gather for many industries, but is especially difficult in the generation sector of the electric power industry"

If it were possible to overcome these difficulties, would the results of the monetary approach be superior in theory to those obtained by the "straightforward" physical asset approach?

**11.1-Staff-246**

Ref: Exh A1-3-2 Attachment 1

LEI describes the methodology, the data selection, data sources and data analysis and manipulation conducted, along with the results of the TFP study. However, the data used and the model are not provided.

Please provide the data set used and the TFP model, and any other model(s) (e.g. for the trend regression analysis referred to in section 6.2.2) used by LEI in its TFP analysis.

The data and model(s) should be provided in working format, such as Microsoft Excel. Where provision of the raw data would reveal confidential or proprietary information, the data may be transformed and provided in an indexed format. Where variables are provided in such a transformed manner, this should be indicated.

Documentation on the data and the model(s) should also be provided to facilitate understanding of the data and model and to link these back to the discussion in LEI's report. Sufficient information should be provided on the design and working of the model, the data used, and the firms used in the data set for the analysis to enable another researcher to replicate the results of LEI's analysis.

**11.1-Staff-247**

Ref: Exh A1-3-2 Attachment 1

OEB staff would like to make an independent calculation of the productivity trend of OPG. A monetary approach would be used to calculate capital cost and the capital quantity index. Please provide the following information *for as many years as the company has data* to calculate productivity trends. It is quite useful to have the required capital cost data for a lengthy sample period even if the O&M expense data aren't available. If there are noteworthy discontinuities in the data, please explain them. Please indicate whether the Company is providing data only for prescribed generating stations or for all generating stations. The latter is satisfactory if it permits a longer sample period:

a) Value of gross additions to hydroelectric plant.
b) Gross value of hydroelectric plant in service and accumulated depreciation on hydroelectric plant.
c) The typical average service life by type of asset used by OPG to determine depreciation rates. These are not required for each year.
d) Total hydroelectric operation, maintenance, and administration (OM&A) expenses by account, itemized by major expenditure category where possible. Please provide any amounts paid for water for power such that it can be removed as it was for the LEI study.

e) Annual depreciation (amortization) charged for hydroelectric plant.
f) The amount of total hydroelectric OM&A related to compensation of company employees. Should this specific dollar figure be confidential or unavailable, please provide a typical percentage of the total (e.g. “about 60%” based on information over 10 years). Does this amount include the cost of pensions and current employee and other post-employment benefits? If so, approximately what percentage of the total is pension and current and post-employment benefits?
g) The weighted average cost of capital, itemized to the extent practicable.
h) The MWh generated by each unit operated by OPG.
i) Nameplate and operational capacity of each hydroelectric generating station operated by OPG.
j) Please identify which units are conventional and which are pumped storage
k) From previous work done for the OEB in the distribution sector, PEG is aware of the Statistical Yearbooks that Ontario Hydro used to produce annually. PEG believes that these documents also contained operational, capacity, production and financial statistics on generation and specifically for Ontario Hydro’s electricity generating plants.
    i. Does OPG possess any summary data publications such as the previous Ontario Hydro Statistical Yearbooks, containing data for Ontario Hydro’s generation assets, operations and production prior to the reorganization resulting from the *Energy Competition Act* of 1998?
    ii. For which years are these documents available?
    iii. If available, please provide the documents.
l) Please provide any data on the allocation of corporate costs to hydroelectric O&M (e.g., allocation of Total or Admin & General OM&A). Please describe the methodology by which Corporate A&G costs were allocated between regulated hydroelectric. Nuclear, other (including fossil) generation and, for the predecessor Ontario Hydro, transmission and distribution.

**11.1-Staff-248**

Ref: Exh A1-3-2 Attachment 2

The Navigant Study filed was finalized on August 17, 2015 and contains 2013 data. This study was not updated for the filing of OPG’s application on May 27, 2016.

a) Please explain why the study was not updated subsequent to the August 17, 2015 study. Would the 2014 data have been available later in 2015 or by early 2016 to provide more current data?
b) Please provide OPG’s views as to why this benchmarking study based on 2013 data should be considered reasonable and representative of OPG’s performance on the prescribed hydroelectric generating assets for the prospective five-year term of 2017 to 2021 inclusive.

**11.1-Staff-249**

Ref: Exh A1-3-2-Attachment 2

Footnote 1 on page 3 states that the Navigant benchmarking is with respect to one year performance, for 2013: "Quartiles are determined by comparing OPG's 2013 performance to the peer group values in each functional area."

In general, hydroelectric generation facilities are long-lived assets. They are also costly to build or replace, but once in service, can often have relatively long periods between major capital investments.

a) Since the benchmarking only looks at one year's worth of performance data for OPG and the comparator group, how reliable are the results provided on pages 12-21 as representative of where OPG ranks against similar utilities on a long-run basis?
b) The Navigant results typically interpret "lowest cost" as being first quartile, while highest cost as being in the fourth quartile. Is this actually a valid way of interpreting the results in all of the dimensions, particularly with respect to capital investments?
    i. Is having lower investment (i.e. being in the first quartile) actually indicative of "superior" performance? For example, could sustained under-investment be indicative of "harvesting" of assets, which will lead to significant investment cost at some point in the future to refurbish or replace the asset?
    ii. Please provide Navigant's views on whether, since only one year's worth of data is examined for all firms in the peer group, the stage in the life cycle of assets could influence which quartile is shown in? For example, with respect to lower capital investments, could the results be materially influenced by one firm having completed a major investment a few years prior, thus obviating the need for major investments for a period of time, relative to most other firms?

**11.1-Staff-250**

Ref: Exh A1-3-2 Attachment 2

Footnote 4 on page 3 of the Navigant study states that dollars shown on pages 3, 13-20 are in $USD, while all other pages are expressed in $CDN.

Please provide the exchange rate or Purchase Power Parity (PPP) conversion factor used to convert $CDN to $USD in this study.

**11.1-Staff-251**

Ref: Exh A1-3-2 Attachment 2

Regarding pages 4 and 5, OPG is ranked in the worst quartile with respect to Public Affairs & Regulatory (PA&R) costs. Footnote 1 on page 5 states:

> The largest components of OPG's regulated Hydroelectric PA&R are the Gross Revenue Charge In lieu of Property Tax ($204M) and the Gross Revenue Charge for water rental fees ($121M). Neither of these charges are controllable by OPG and both are prescribed by regulation.

Is it possible to break out OPG's PA&R costs to isolate these "non-controllable" costs, and to do similar break outs for other firms in the comparator group, so that some form of “apples-to-apples” comparison of such costs could be made? If an analysis is possible, why was it not done? If it is not possible, please explain the reasons for this.

**11.1-Staff-252**
Ref: Exh A1-3-2-Attachment 2
Regarding page 18 on PA&R costs, the study indicates that the range of costs within the total group is from $0(000/MW) to $153(000/MW), with costs expressed in $USD.

a) Please provide a detailed description of what constitutes PA&R costs for:
    i. OPG; and
    ii. Other hydroelectric generating utilities in the comparator group.
b) Please explain why there appears to be such a wide cost range per MW. What characteristics of the operating environments, jurisdictions that they operate in, or age, technology or water source are the major reasons impacting on the variation in these costs?

**Issue 11.2**
**Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?**

**11.2-Staff-253**
Ref: Exh A1-3-2 page 16
OPG proposes that the current hydroelectric payment amounts as approved in EB-2013-0321 be used as the “going in” rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. The current payment amounts reflect the OEB’s findings in EB-2013-0321 to only allow OPG to recover its cash requirements for pensions and other post-employment benefits.

Are there one-time OM&A costs that were factored into the approved 2014-2015 hydroelectric payments amounts? Please identify all of these and the approved costs. Please explain why OPG has not adjusted the “going-in” hydroelectric payments for these other “one-time” costs.

**11.2-Staff-254**
Ref: Exh A1-3-2 page 16
The current hydroelectric payment amounts as approved in EB-2013-0321 are used as the “going in” rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. Please identify the approximate impact on base payment amounts if OPG had filed a rebasing application for the regulated hydroelectric facilities for 2017.

**Nuclear**

**Issue 11.3**

**Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?**

**Issue 11.4**
**Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?**

**11.4-Staff-255**
Ref: Exh A1-3-2 pages 35-36
Ref: Exh F4-3-1 page 6
OPG notes that operational effectiveness is one of the four outcomes that the OEB seeks to promote through the RRFE, specifically continuous improvement in productivity and cost performance. OPG lists the ways that the nuclear business achieves these outcomes in Exh A1-3-2.

a) OPG states that there are "staffing and compensation strategies designed to ensure key resources are available when needed, to minimize risk, and to ensure safe and efficient operations."
    i. Have these staffing and compensation strategies been revised recently? If yes, please explain the changes.
    ii. Please explain the effectiveness of the staffing and compensation strategies given the higher than expected number of retirements in the nuclear business in 2015, of which "over two thirds of the 2015 retirements were in the critical operations, maintenance and technical roles and will need to be replaced."
b) OPG states that the "performance-based planning process allows OPG to track the company's results against targets, and to set appropriate targets for each successive year, creating a cycle of continuous performance and cost efficiency improvement." Please provide examples of the cycle of continuous performance and cost efficiency improvement.

**11.4-Staff-256**
Ref: Exh A1-3-2 page 28 to 33
Ref: Exh A2-2-1 Attachment 1 page 3
Ref: Exh F2-1-1 Attachment 1 page 89
OPG's nuclear Custom IR framework is based on five individual nuclear revenue requirements, but includes incremental year over year reductions based on a proposed 0.3% stretch factor. OPG's derivation of the stretch factor is based on production weighting top quartile performance by Darlington (0% stretch) and fourth quartile performance by Pickering (0.6% stretch).

The OPG 2016-2018 Business Plan states that "Starting in 2016, OPG is adopting Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness."

The EUCG indicator results summary of value for money performance is provided at page 89 of Attachment 1 of Exh F2-1-1. OPG's average nuclear TGC is $50.61/MWh, while the median is $42.53/MWh and the best quartile is $37.12/MWh.

Please explain why a 0.3% stretch factor is appropriate.

**Issue 11.5**
**Is OPG's proposed mid-term review appropriate?**

**11.5-Staff-257**
Ref: Exh A1-3-3, page 12
The evidence states that, "Subject to the OEB concluding that rates are no longer just and reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years. However, while the revenue requirement must be determined on a five-year basis, no such limitation exists for the determination of production."

Please explain on what basis the OEB would determine that "rates are no longer just and reasonable."

**11.5-Staff-258**
Ref: Exh A1-3-3
OPG states that the scope of its mid-term review would be limited to the nuclear production forecast from July 1, 2019 through December 31, 2021, revisions to forecast fuel costs, and disposition of audited balances in deferral and variance accounts.

Does OPG propose to file for a mid-term review if the difference between the production forecast approved in the EB-2016-0152 proceeding is insignificantly different from the future OPG approved business plan? If not, what materiality test does OPG propose to use to determine whether or not the difference in the production forecast is significant enough to warrant a mid-term review?

**11.5-Staff-259**
Ref: Exh H1-1-1, page 30, Exh A1-3-3, page 12
In its evidence, OPG describes the entries to be included in the Mid-term Nuclear Production Variance Account, as follows:

> To determine entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be reduced by an amount determined as a monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year.

a) Please provide a sample calculation that would show the practical application of methodology outlined in Exh H1-1-1.

b) In Exh A, it's stated that "the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years". How is OPG's proposed adjustment to fuel cost in the Mid-term Nuclear Production Variance Account consistent with the preceding statement?

**11.5-Staff-260**

Ref: Exh E2-1-1, Tables 1 and 2, Exh I1-3-1, Table 1

OPG has provided the monthly production forecast in Table 2 of Exhibit E2-1-1 with two significant digits of numerical precision. The annual production forecast in Table 1 of Exhibit E2-1-1 has been provided to three significant digits of numerical precision. When performing calculations in this application, such as the derivation of the nuclear payment amounts in Exhibit I1-3-1, OPG has mostly used data that is at least 3 significant digits of numerical precision.

a) Please provide an updated version of Table 2 showing the monthly production forecast to three decimal places.
b) Does OPG have any objection to the use of the monthly production forecasts to three decimal places as the basis for the determination of balances in the mid-term nuclear production variance account?

**11.5-Staff-261**

Ref: Exh A1-3-3 pages 10-14

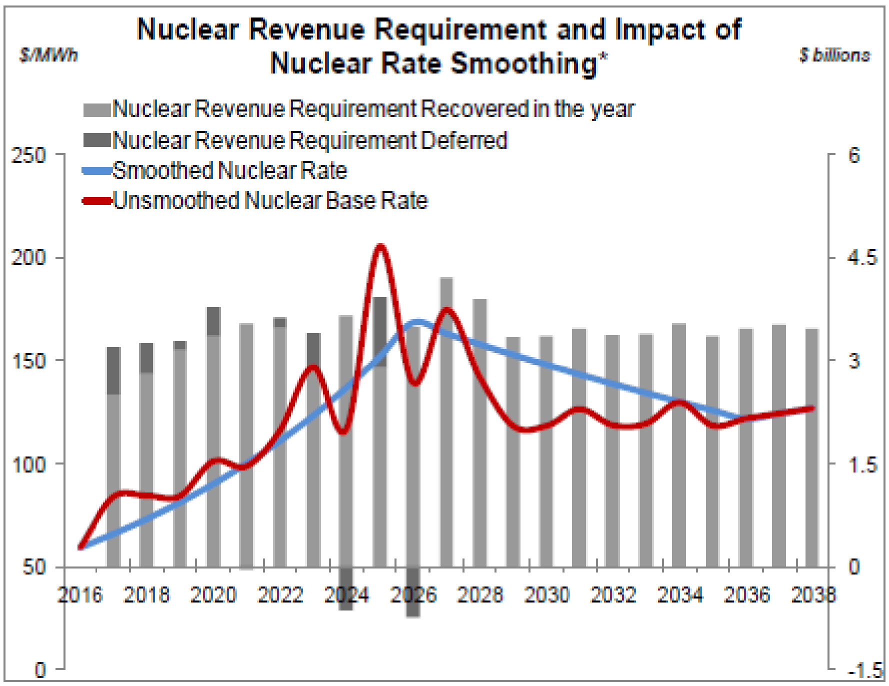
OPG is proposing a mid-term nuclear production review to address the inherent uncertainty of out-year production forecasts in a five-year forecast cycle. OPG proposes a Mid-term Nuclear Production Variance Account to accumulate revenue deviations that may result from an updated production forecast. OPG states that "….a completely variable rate provides a strong financial incentive to OPG to achieve or surpass the OEB approved production forecast…."

a) OPG lists five risks that may make a mid-term production review attractive. Three of these five risks are inherent, generic risks to any production forecast (public policy changes, regulatory requirements and approvals, aging facilities), one is specific to this application (DRP and post-DRP loss rates), and one is a sub-issue to regulatory requirements specific to this application (CNSC approval to extend Pickering operations). Does OPG consider the proposed review a "one-time" only occurrence or a recurring event that could be included in future applications?
b) Has OPG prepared any analysis or accessed any research that assesses the impact of a mid-term production review on incentives? Does OPG have any examples from other jurisdictions where updating production forecasts has increased productivity or efficiency?

**Issue 11.6**

**Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?**

**11.6-Staff-262**
Ref: Exh A2-2-1 page 5
Ref: Exh A1-3-3, page 6
Ref: Exh A1-3-3 Chart 1
The 2016-2018 business plan states that nuclear rate smoothing will moderate price spikes during DRP and eventual Pickering closure period, and the following graph is provided in the business plan.




* Information beyond 2021 is included for illustrative purposes

a) Please explain the DRP and Pickering events that contribute to each swing in the unsmoothed rate in the period 2016 to 2038.
b) OPG states at page 6 of Exh A1-3-3 that O. Reg. 53/05 "requires the OEB to set smoothed annual payment amounts." Please provide the specific regulation reference requiring "the OEB to set smoothed annual payment amounts."
c) OPG has proposed a smoothed rate to reflect a constant 11% per year base payment amount increase during 2017 to 2021. Section 6(2)12(i) of O.Reg. 53/05 states that the OEB "shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the payment amount that is used in the determination of the undeferred payments". In OPG's view, is the requirement of the regulation met if the swings in the unsmoothed rate are dampened, but not at a constant percent increase on base payment amounts?
d) Please explain the "Total" column in Chart 1 on page 6.

**11.6-Staff-263**
Ref: Exh A1-3-3, page 1

The evidence at page 1 states, “The rate impact and volatility in the test period are driven by reduced production as Darlington units are taken out of service to be refurbished, partially offset by production at the Pickering generating station in 2021 due to the plan to extend operations, and costs associated with the Darlington Refurbishment Program (“DRP”).”

Please provide the analysis that summarizes the rate impact and smoothing requirement of the scenario in which Pickering operations are not extended beyond 2020.

**11.6-Staff-264**
<u>Ref: Exh A1-3-3, page 2</u>
<u>Ref: Exh A1-3-3 Chart 1</u>
The evidence states, “The regulation requires that, for each year of the deferral period, the OEB must approve a nuclear revenue requirement and must also determine a portion of that approved revenue requirement to defer. The OEB is required to make this decision with the aim of stabilizing year-over-year changes in payment amounts.”

a) A new ONFA reference plan is expected in 2017. Does OPG agree that significant riders are possible when the nuclear liability account is disposed? Can the ratepayer expect smoothing or stability under circumstances such as these?
b) OPG’s proposal results in a drop in payment amounts (including riders) in 2017 vs 2016. Does OPG consider this impact to be consistent with smoothing or stability?
c) In OPG’s view, does the regulation prohibit the OEB from considering deferral and variance account recovery in the making of smoothed or stabilized payment amounts?

**11.6-Staff-265**
<u>Ref: Exh A1-3-3, page 7</u>
Chart 2 summarizes the unsmoothed revenue requirement, production and average payment amount for the period 2017-2036.

a) What pension accounting assumptions underpin the analysis?
b) Please prepare a similar chart for the smoothed scenario, assuming 11% increases in payment amounts in 2017-2021 and 2022-2026 (as per Chart 3), and recovery of the rate smoothing deferral account at the completion of DRP on a straight line basis over 10 years. Please show the recovery of the rate smoothing deferral account on a separate line. Please list assumptions.

**11.6-Staff-266**
<u>Ref: Exh A1-3-3 page 4 and Chart 3</u>
Chart 3 summarizes the smoothing alternatives OPG considered, and compares projected outcomes on the basis of several financial and bill impact criteria and transition to the post-smoothing period. Please confirm that the financial criteria refer to OPG and not the nuclear business.

**11.6-Staff-267**

Ref: Exh A1-3-3 page 4 and Chart 3

OPG used two financial metrics to gauge the potential impact of rate smoothing. One of the metrics was Debt to EBITDA ratio. OPG's preferred threshold for Debt to EBITDA ratio is equal to or less than 5.5.

a) Please provide the Debt to EBITDA ratio for the 2012 to 2015 period for OPG.
b) All alternatives in Chart 3 appear to have ratios greater than 5.5 in the 2017-2021 period. Considering that uncertainty of outcomes increases over time, shouldn't the near term ratios have greater weight in choosing options?

**11.6-Staff-268**

Ref: Exh A1-3-3 pages 4 and 9 and Chart 3

OPG refers to a ratio of Funds from Operations (FFO) Adjusted Interest Coverage ratio as a key financial indicator.

a) OPG states that higher values for the interest coverage ratio are preferred with a minimum target of three. Please provide the FFO Adjusted Interest Coverage ratio for the 2012 to 2015 period for OPG.
b) In Chart 3 there is a line labeled "Interest Cost/Deferred Revenues Ratio". Is this a mis-labelling or is the reported ratio equivalent to an FFO Adjusted Interest Coverage ratio? If not, please provide the FFO Adjusted Interest Coverage ratio for all the alternatives set out in Chart 3.
c) On page 9 OPG states that the Interest Cost/Deferred Revenues is ratio is an indicator of intergenerational equity. What is the target for the Interest Cost/Deferred Revenues ratio?

**11.6-Staff-269**

Ref: Exh A1-3-3 page 8-9

OPG has five criteria for choosing a smoothing option. Did OPG have a weighting system for the criteria or were all criteria given equal weight in the choice of options?

**11.6-Staff-270**

Ref: Exh A1-3-3 pages 11-12

OPG states it is extremely difficult to accurately forecast OPG's annual nuclear production over a five-year period and has also stated that it has never met its own two-year forecast (as approved by the OEB in prior years). OPG profiles five uncertainties that may have an impact on production (and implicitly associated costs):

1. Public policy changes
2. Pickering extended operations
3. Execution of Darlington refurbishment program
4. Regulatory requirements and approvals
5. Aging facilities

OPG does not quantify these uncertainties. Please provide "high and low" forecasts for production and associated cost impacts for each of these uncertainties. Please use the attached spreadsheet.

**General**

**Issue 11.7**
**Is OPG's proposed off-ramp appropriate?**

**11.1-Staff-271**
Ref: Exh A1-3-2 page 23
In section 2.7, OPG has proposed an off-ramp mechanism pertaining to a situation whereby OPG's regulated ROE is outside of a deadband of +/- 300 basis points from is allowed ROE. In this case, a regulatory review could be initiated.

The proposal is that the regulated ROE would be determined on the basis of all rate regulated generation assets (i.e., both hydroelectric and nuclear).

a) In this application, the payment setting plans for nuclear and regulated hydroelectric generating assets will be different in terms of the economic and cost-recovery basis. Further, cost recovery for the nuclear generating assets is complicated by the proposed rate smoothing mechanism. How will the actual regulated return on equity for regulated generation assets be calculated over the 2017-2021 term plan?
b) Since the regulated return is based on both nuclear and regulated hydroelectric generation assets, would the regulatory review be on both the nuclear and hydroelectric plans?
c) While OPG labels this an "off-ramp", it indicates that the +/- 300 basis point deviation would be used to determine "whether a regulatory review may be initiated." [Emphasis added] This implies less than certainty that the off-ramp occurs.
    i. Under what conditions, beyond the 300 basis point deviation between achieved and approved returns, does OPG consider that a review and/or off-ramp would be required?
    ii. Under what conditions does OPG consider that a review and/or off-ramp would not be required even when the deviation between actual and approved regulated returns exceeds 300 basis points?

**IMPLEMENTATION**

**Issue 12.1**
**Are the effective dates for new payment amounts and riders appropriate?**