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Ontario

BY E-MAIL

February 21, 2014

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
Board File No. EB-2013-0321

Please find attached Board staff's interrogatories with respect to Ontario Power Generation Inc.'s application for 2014-2015 payment amounts. The grouping and numbering of interrogatories is consistent with the final issues list which was issued on February 19, 2014.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications & Regulatory Audit

Attach

Board Staff Interrogatories
Ontario Power Generation Inc. ("OPG")
2014-2015 Payment Amounts
EB-2013-0321
February 21, 2014

GENERAL

0-Staff-1

Revenue Requirement Work Form

OPG filed its application for 2014-2015 payment amounts on September 27, 2013. A Revenue Requirement Work Form ("RRWF") was filed with the application. On December 6, 2013, OPG filed an impact statement that revised the revenue requirement and the payment amounts. Another version of the RRWF was filed with the impact statement, in which the September 27, 2013 data were replaced.

Please combine both versions of the RRWF by revising the original RRWF. Please insert additional columns. For some tables 2 additional columns are required and for some tables 3 additional columns are required. The current "2014 OPG Proposed" column would be renamed "2014 OPG Proposed 27/9/13" and a new column "2014 OPG Proposed 6/12/13" would be inserted.

Please file the revised and completed RRWF in PDF and working Excel versions.

0-Staff-2

2013 Actual Results

Procedural Order No. 1 established March 19, 2014 as the date on which OPG will file interrogatory responses. To the extent that 2013 actual results are available, please update the evidence accordingly. Updated tables should consist of a new column "2013 Actual" beside "2013 Budget". The spreadsheets that were filed should be updated in the same manner.

As above, please provide updated deferral and variance account evidence in Exh H1-1-1 including the account balances and applicable tables to reflect 2013 actual amounts. In addition, please provide the proposed consequential changes (e.g., proposed payment riders).

Please reflect 2013 actual results in the responses to interrogatories where applicable.

0-Staff-3

Ref: Exh A1-4-3, CNSC Decision on Operating Licence for Pickering (August 9, 2013), O. Reg. 53/05

In the evidence at Exh A1-4-3 page 1, it states that, "In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station." Board staff notes that on August 9, 2013, the CNSC issued a one-site Power Reactor Operating Licence to OPG for the operation of the Pickering Nuclear Generating Station.

The prescribed generation facilities as listed in O. Reg. 53/05 refer to Pickering A and Pickering B. Please reconcile the change in overall operations of Pickering with O. Reg. 53/05.

Issue 1.2
Are OPG's economic and business planning assumptions for 2014-2015 appropriate?

1.2-Staff-4
<u>Ref: Exh A2-2-1 Attachment 1 and Attachment 2, Exh N-1-1 Attachment 4</u>
OPG filed the 2014-2015 payment amounts application on September 27, 2013. In the evidence at Exh A2-2-1 Attachment 2, the 2013-2015 Business Planning Instructions were filed. Those instructions, dated July 20, 2012, provide context, guidelines, key process changes and a schedule in addition to instruction. The schedule at page 9 of the document lists 2012 activities from June to December and indicated that OPG Board approval of the 2013-2015 Business Plan was scheduled for November 15.

a) The 2013-2015 Business Plan was filed at Exh A2-2-1 Attachment 2. The 2013-2015 Business Plan is dated May 16, 2013. The recommendation for submission to the OPG Board states that the Business Plan incorporates the OM&A and capital plans provided to the Board in November 2012. What are the reasons for the delay in finalizing the 2013-2015 Business Plan?
b) On December 6, 2013, OPG filed Exhibit N to show the impact of certain material changes resulting from OPG's 2014-2016 Business Plan. That Business Plan was filed as Attachment 4 and is dated November 14, 2013. Please file the 2014-2016 Business Planning Instructions.

Issue 1.3
Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?

1.3-Staff-5
<u>Ref: Exh A2-1-1 Attachment 1, Attachment 2b</u>
The OEB has approved OPG's request to use US GAAP for ratemaking purposes effective on January 1, 2012.

a) Please summarize US GAAP accounting requirements that have been included in this application that result in different accounting treatments from OPG's last payment order proceeding under Canadian GAAP.

b) Please identify changes arising from US GAAP reporting for assets, liabilities, revenues, expenses, gains and losses.
c) Please indicate if OPG adopted any new US GAAP accounting standards or requirements since OPG's adoption of US GAAP in 2012, and if so, please identify the associated financial impacts.

1.3-Staff-6
Ref: Exh A2-1-1 Attachment 1, Attachment 2b
Under US GAAP, Accounting Standard Codification 980 ("ASC 980") sets out rate-regulated financial reporting requirements for rate-regulated entities. The accounting requirements under ASC 980 are compulsory and not optional for rate-regulated entities.

a) Please explain how the ratemaking actions specific to OPG and the general regulatory accounting requirements of the Board have been incorporated in OPG's financial reporting in its audited financial statements effective January 1, 2012.
b) Under ASC 980, please confirm OPG's understanding that the rate regulator has the authority to set and approve regulatory accounting policies which must then be included in the financial statements of the rate-regulated entity. If not, please explain.
c) Please confirm that a rate-regulated entity regulated by the Board should first seek approval of any changes to its regulatory accounting policies from the Board through a rate order or an accounting order prior to making these changes? If not, please explain.

RATE BASE

Issue 2.1
Are the amounts proposed for rate base appropriate?

2.1-Staff-7
Ref: Exh A2-1-1 Attachment 1 pages131-135 Note 15, Attachment 2b pages 53-56 Note 18, and Exh B2-3-1 Table 1
Please provide a comparative analysis of the 2012 consolidated financial statements' regulated segments in Note 15 to the 2012 prescribed facilities financial statements' regulated segments in Note 18 showing comparisons of each line item for each segment's financial statement, the resulting financial differences and explanation for these differences.

2.1-Staff-8
Ref: Exh A2-1-1 Attachment 1 pages131-135 and Exh B2-3-1 Table 1
Please provide a breakdown of the 2012 consolidated financial statements' "Unregulated Hydroelectric" segment in Note 15 by sub-segments for "Newly Regulated Hydroelectric" and "Remaining Unregulated Hydroelectric" for each line item of the financial statements on a pro-forma basis.

2.1-Staff-9

Ref: Exh A2-1-1 Attachment 1 pages131-135 Note 15, Attachment 2b pages 53-56 Note 18 and Exh B2-3-1 Table 1

For the “Newly Regulated Hydroelectric” facilities incorporated into OPG’s financial reporting, please use OPG’s 2012 consolidated financial statements as a baseline and provide on a pro-forma percentage basis for each statement, the estimated portion which would represent the “Regulated” and “Unregulated” businesses or segments inclusive of eliminations, where applicable (i.e., regulated and unregulated percentages for each financial statement).

2.1-Staff-10

Ref: Exh A2-1-1 Attachment 1 pages131-135 and Exh B2-3-1 Tables 1 and Exh B2-4-1 Table 1 Exh B2-3-1 Table 2 and Exh B2-4-1 Table 2

For Newly Regulated Hydroelectric assets,

a) Please provide a reconciliation of “Newly Regulated Hydroelectric” assets captured in the 2012 consolidated financial statements’ Unregulated Hydroelectric in Note 15 Business Segment “Segment property, plant and equipment, net $4,789M” and the 2012 Actual NBV for the Newly Regulated Hydroelectric of $2,511.9M (i.e., Exh B2-3-1 Table 1: Line 28 column e amount of $3,201.5M minus Exh B2-4-1 Table 1 Line 28 column d amount of $689.6M).
b) Please provide a reconciliation of “Newly Regulated Hydroelectric” assets captured in the 2013 consolidated financial statements in the Unregulated Hydroelectric of Note regarding the Business Segment property, plant and equipment, net $x,xxxM” and the 2013 Budget NBV for the “Newly Regulated Hydro-electric” of $2,502.2M (i.e., Exh B2-3-1 Table 2: Line 9 column e amount of $3,247M minus Exh B2-4-1 Table 2 Line 9 column e amount of $744.8M) or the 2013 Actual NBV arising from updated aforementioned tables.

2.1-Staff-11

Ref: Exh A2-1-1 Attachment 1, Attachment 2b, Ontario Regulations 312/13 and 53/05 and Exh B2-3-1 Table 1

Ontario Regulation 312/13 at section 4(3) (ii) specifies:

> Subsection 6 (2) of the Regulation [53/05] is amended by adding the following paragraph:
> 11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:
> ...
> ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.’s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax

> effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

In relation to the referenced regulation in respect of the newly regulated hydroelectric facilities and given that OPG's 2013 audited financial statements will be released in the near future, please confirm whether it is OPG's view that the 2013 financial statements represent OPG's most recent audited financial statements for the purposes of this 2014-2015 payment order application. If not, please explain.

2.1-Staff-12
<u>Ref: Exh N-1-1 Attachment 4 page 11, Exh D1-1-1 Table 1 and Exh D2-1-2 Table 1</u>
The 2014-2016 Business Plan at page 10 presents a table detailing Capital Expenditures over the 2013-2016 period.

a) Please explain why the numbers shown for Nuclear, Hydroelectric Regulated, Hydroelectric Newly Regulated, Niagara Tunnel and Darlington Refurbishment differ from the Capital Expenditures numbers shown in Exhibit D1 and D2.
b) What would be the impact on Nuclear and Hydroelectric 2014 and 2015 rate base, if the capital expenditures shown in the Business Plan were reflected?

CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 3.1
What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

3.1-Staff-13
<u>Ref: Exh A1-2-2 page 1</u>
On page 1, one of the approvals that OPG is seeking is stated as:

> Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the Board's Cost of Capital Report, and currently forecast at 8.98 per cent for 2014 and 2015, as presented in Ex. C1-1-1.

Please confirm that the 8.98% refers to the return on equity ("ROE") as issued by the Board in its letter of February 14, 2013 for rates effective May 1, 2013, and not the "combined rate of return" as stated above. In the alternative, please document the basis for OPG's requested approval.

3.1-Staff-14
<u>Ref: Exh C1-1-1 page 1</u>
At the bottom of page 1, OPG states:

> OPG is not proposing any changes to its capital structure as there have been no significant changes in the risks faced by OPG's **regulated** asset portfolio that are not otherwise addressed by proposals to establish new variance and/or deferral accounts as described in Ex. H1-3-1. **[Emphasis added]**

Board staff notes that a key aspect of OPG's application is a significant change to OPG's "regulated asset portfolio" through the addition of "newly regulated hydroelectric" facilities, per O.Reg. 312/03,

Please confirm that OPG is of the view that the newly regulated hydroelectric facilities have similar business risks to the existing prescribed nuclear and hydroelectric generation assets. If yes, please provide OPG's reasons for this view.

3.1-Staff-15

<u>Ref: Exh C1-1-1 page 2</u>

In the application filed on September 27, 2013, OPG proposed that the ROE be updated based on Consensus Forecasts [and other Statistics Canada/Bank of Canada and Bloomberg LLP] data for three months prior to the effective date of the payment rates order, in accordance with the Cost of Capital Report and with the Decisions in its previous payment order EB-2010-0008.

On November 21, 2013, the Board issued the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), in which the Board stated that the Cost of Capital parameters would normally be updated once a year.[1] This was repeated in the letter issued November 25, 2013 announcing the Cost of Capital parameters effective for cost of service rates applications effective January 1, 2014.

a) In light of the Board's process to calculate the Cost of Capital parameters only once annually, does OPG intend to change its proposal and adopt the 2014 ROE as announced in the Board's letter of November 25, 2013?
b) If OPG proposes an alternative, including updating the ROE based on data three months prior to the effective date of the payments order, please provide OPG's rationale for doing so, and why it does not consider the 2014 Cost of Capital parameters issued by the Board on November 25, 2013 to be suitable for setting its 2014-2015 payments.

3.1-Staff-16

<u>Ref: Exh C1-1-1 page 2</u>

At the bottom of page 2, OPG states:

[1] *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), November 21, 201, page 10

> For the second year of that test period (2015), the ROE will be set at the same time as the first year but using data from Global Insight instead of the *Consensus Forecasts* used by the OEB because the *Consensus Forecasts* data is only projected for 12 months.

This is the same approach as OPG had proposed, and the Board had approved, in OPG's prior payments application.

a) Has OPG investigated sources other than Global Insights for economic forecasts that extend beyond the one-year horizon provided by *Consensus Forecasts*? If so, which ones (e.g. Conference Board of Canada)? If not, why not?
b) The Board's use of *Consensus Forecasts* is derived, in part, on that publication's use of multiple economic forecasting sources and the use of mean/median/consensus results from the pool of forecasters surveyed. Doing so may reduce the forecasting error or bias of a single forecaster and hence may have a greater likelihood of being close to the future actuality. Please explain why OPG is relying solely on Global Insights for the forecast beyond the first test year.

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

3.2-Staff-17
<u>Ref: Exh C1-1-2 pages 4-5</u>
At the bottom of page 4 and continuing on page 5, OPG documents the following:

> The cost of planned new and refinanced corporate debt and project-related debt for 2013, 2014 and 2015 is based on a forecast of 10-year Long Canada Bond[s] as published in April 2013 by Global Insight, a third party independent market source.

Year	**Q1**	**Q2**	**Q3**	**Q4**
2013	1.87	2.10	2.38	2.39
2014	2.50	2.65	2.76	2.80
2015	2.87	3.05	3.22	3.44

> The long-term interest rates forecast for the 10-year Government of Canada bonds are provided in Chart 1. As discussed below, a credit risk spread for OPG of 132 basis points is added to the Global Insight rates notes in Chart 1 to determine the forecast rate for OPG's OEFC debt in 2013, 2014 and 2015.

Chart 1
Forecast 10-year Long Canada Bond Rates

Year	**Q1**	**Q2**	**Q3**	**Q4**
2013	1.87	1.95	2.08	2.26
2014	2.40	2.54	2.64	2.67

2015	2.71	2.85	3.15	3.37

* Annual forecast

OPG's credit spread at the end of 2012 was 132 basis points and this spread has been used for 2013, 2014 and 2015.

a) The table at the top of page 5 contains different numbers than are shown in Chart 1. Please identify this first table, and explain what purpose it serves with respect to OPG's evidence on its long-term debt.
b) What does the footnote "* Annual forecast" below Chart 1 refer to?
c) What is OPG's actual weighted average debt rate for its corporate and project-related debt for 2013?
d) What is OPG's credit spread as of December 31, 2013?
e) Please provide a copy of the April 2013 Global Insight document referenced at the bottom of page 4.
f) If OPG has a more recent copy of the Global Insight publication, please provide a copy of the most recent publication.

3.2-Staff-18

<u>Ref: Exh C1-1-3 pages 1-3, Exh C1-1-3 Table 2</u>

a) Please provide the source data and the calculations for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities of 1.22% for 2014 and 2.23% for 2015.
b) Please provide any more recent estimates for short term interest rate forecasts for 2014 and 2015 that OPG has.
c) Canadian, U.S. and other major central banks have tended to stay the course on overnight and other central bank rates as they balance inflationary and national and global economy stimulus and growth per governmental policies. Please explain why an increase of about 1 percentage point in 2015 is still to be expected.
d) On pages 1-2 of Exh C1-1-3, OPG explains the purpose of the accounts receivable securitization. In Table 2, OPG shows that it made little use of this program in 2012, with an average principal of $8.3M. OPG explains that it intends to use the A/R securitization program beginning in 2013 Q4 with an average monthly principal balance of $195M and that this will continue for the 2014-2015 test period.
    i. Did OPG use the securitization program in 2013 Q4 as forecasted?
    ii. Please explain why OPG has decided to borrow under the A/R securitization program, when it did not need to avail itself to this short-term funding mechanism in 2012 or most of 2013 to any great extent.

CAPITAL PROJECTS

Regulated Hydroelectric

Issue 4.2
Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

4.2-Staff-19
Ref: Exh D1-1-1
Please refer to the table below prepared by Board staff.

Hydroelectric Newly Regulated							
(in millions)	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Proposed	2015 Proposed	average (2010-13)
Ottawa-St. Lawrence Plant Group	$48.4	$27.1	$41.0	$31.7	$32.2	$39.0	$37.1
Central Hydro Plant Group	$4.8	$10.1	$8.8	$8.5	$26.1	$33.2	$8.1
Northeast Plant Group	$6.4	$10.1	$21.6	$15.6	$20.4	$19.5	$13.4
Northwest Plant Group	$9.0	$14.1	$8.7	$15.6	$12.2	$8.3	$11.9
Total	**$68.6**	**$61.4**	**$80.1**	**$71.4**	**$90.9**	**$100.0**	$70.4

a) Please confirm that capital expenditures on the newly regulated hydroelectric plant averaged about $70M annually between 2010 and 2013.
b) What material changes in plant condition underpin the $25M or 35% increase, as compared to the historical average, in capital expenditures, in 2014 and 2015?
c) Please explain why these changes in plant condition could not have been anticipated and addressed during the 2010-2013 period?

Issue 4.4
Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.4-Staff-20
Ref: Exh D1-2-1 page 115
OPG states that it did not recommend cancelling the Niagara Tunnel Project ("NTP") since it would result in an expenditure of $563M, including $100M in shut down costs, and nothing to show for it.

Is the $100M in shut down costs, in OPG terminology, a project " identification" or "initiation" or "definition" or "execution" phase type number when it comes to accuracy i.e. is the amount an estimate or is it a thoroughly investigated and detailed amount?

4.4-Staff-21
Ref: Exh D1-1-2 page 13, Exh D1-2-1 page 2, Attachment 8B and EB-2007-0905/Exh D1-1-2 Attachment A Appendix C page 3
OPG indicates that it placed $1,474.2M in service in 2013 for the NTP. OPG also states that O. Reg. 53/05, section 6(2)4 requires the Board to ensure that OPG recovers the capital and non-capital costs of the NTP approved by the OPG Board of Directors prior to the first payment amounts order and to determine the prudence of any expenditures beyond the OPG Board approved amount.

In the Recommendation for Submission to the Board of Directors, dated May 21, 2009, OPG states:

> Once in-service, the NTP will form part of OPG's regulated rate base. Under O.Reg 53/05 the OEB is required to ensure that OPG recovers the original project budget of $985M approved by OPG's Board and this amount will not be subject to a prudence review by the OEB. However, the incremental project costs above the original approval will be subject to a prudence test. Under the OEB's prudence test, OPG's actions are assumed to be prudent unless challenged on reasonable grounds. In assessing prudence, the OEB will consider what information was known or should have been known at the time key decisions were made and what third-party expert advice was sought to assist in decision making. Hindsight is not to be used in determining prudence. Given the extensive volume of studies conducted prior to project execution and the nature of independent advice sought throughout the process (leading international consultants, academia, Dispute Review Board, Contract Oversight Committee, etc.), OPG is well positioned to make the case that the entire capital cost should be recoverable. OPG will, of course, have to demonstrate ongoing diligence in project execution as part of its case for recoverability. However, given the significant cost over-runs associated with the project, the OEB will be likely to review the matter in detail and therefore regulatory risk remains.

In the original Full Release Business Case Summary ("BCS"), dated July 28, 2005, filed in the 2008-09 Payments Amounts proceeding, at page 3 OPG indicated that "Under Ontario Regulation 53/05, effective April 1, 2005, the Project will become part of OPG's regulated hydroelectric assets and OPG will be given a fair opportunity to recover prudently incurred costs through regulated rates."

a) Of the total NTP related costs that have been or are proposed to be recovered from ratepayers, please confirm whether $985M is the amount that OPG considers as "OPG Board of Directors approved". What is the exact amount that OPG views as in excess of the OPG Board approved amount?
b) Appendix C of the BCS, dated July 28, 2005, provides a project risk profile for the NTP. Mitigating activity is identified regarding the risk that the contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report ("GBR"). Mitigating activities include "The GBR is based on extensive field investigations carried out over a 10-year period and knowledge gained through the construction of the SAB2 tunnels." and "The 3-stage GBR process used facilitates contractor input and concurrence before construction begins".
    i. Are the SAB2 tunnels at the same depth as the NTP?
    ii. To what extent, as compared to the planned route for the NTP, do the SAB2 tunnels travel through the same Queenston shale environment?
c) Please compare and contrast the excavation or boring technique used for SAB2 with that used in the NTP. Is it the case that the <u>only</u> risk mentioned in Appendix C of the BCS regarding Queenston shale, the host rock formation for the majority of the tunnel, is its swelling properties when exposed to fresh water? At the time the

Business Case was prepared was OPG aware of any other geotechnical risks that could be associated with Queenston shale?

d) In OPG's view how successful were the aforementioned mitigating activities in reducing, if not eliminating the noted risk?
e) To what extent would the costs in excess of $985M be greater had the mitigating activities not taken place?

4.4-Staff-22

Ref: Exh F5-6-1 and Exh D1-2-1

In the Executive Summary of the Niagara Diversion Tunnel Report (the "Report"), dated September 9, 2013, the author, Roger Ilsley notes that he was requested by "Tory's [sic] to review all pertinent geotechnical investigations conducted and reports prepared for the design and construction of the 14.4m excavated diameter, approximately 10.4 Km long (as designed vs. 10.2 Km constructed), Niagara Tunnel Diversion." The author indicates that he "…. formed an opinion that these site investigations addressed the appropriate design and construction issues and that the studies undertaken were completed to professional standards and exceeded those standards in some cases."

a) Please provide a copy of the Terms of Reference or equivalent between OPG and Roger Ilsley that engaged Roger Ilsley to prepare the Report.
b) Is it correct that the Tunnel Boring Machine ("TBM") which was used to bore/ construct the tunnel was at that time the largest open gripper main beam TBM in the world? In preparing the report did Mr. Ilsley specifically review whether the geotechnical investigations conducted by OPG were appropriate for the boring technology actually utilized?
c) The Report summarizes the recommendations made by the Dispute Resolution Board ("DRB"). With respect to the issue of Excessive Overbreak, the Report states that, "Although the Design Build Agreement indicated that if Differing Surface Conditions are encountered, the resolution of such claims should be held in abeyance until tunnel excavation was compete, the DRB believed that the consequences of the misunderstandings that had led to both the large overbreak quantities and the related impacts had been so material that some form of resolution was needed."
    i. Please elaborate on the nature of the misunderstandings that consequently led to the large overbreak.
    ii. Please explain why OPG considers it reasonable that OPG's ratepayers bear 100% of the portion of the costs that are in excess of the initial ~$0.9B budget approved by OPG's Board of Directors, which resulted from this misunderstanding between OPG and Strabag.

4.4-Staff-23

Ref: Exh D1-2-1

In the EB-2010-0008 proceeding, OPG filed a number interrogatory responses (pertaining to the NTP, under issue 4.2 - *Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate* *and supported by business cases?)* These are Staff # 20, 21; AMPCO # 7,8,9;CCC # 15,16; Energy Probe # 8, 9, 10, 11, 12, 13, 14, 15, 16, 17; SEC # 44,

Please file these interrogatories and their responses (updated as necessary).

4.4-Staff-24

Ref: Exh D1-2-1 Attachment 8A

The Business Case Summary, titled Superseding Release for Niagara Tunnel Project and dated May 2009 considers a number of alternatives in light of the difficulties encountered by the contractor in excavating the tunnel though the Queenston shale formation. The recommended alternative sees the cost of the project rising from $0.985B to $1.6B. The table below, from page 6 of the May 2009 BCS, presents various financial measures of the recommended alternative which was approved by OPG's Board of Directors.

Financial Measure	Original Approval July 28, 2005 ($985M; June 2010 In-Service)		Superseding Release May 21, 2009 ($1.6B; Dec. 2013 In-Service)	
		in 2009 $		in 2009 $
LUEC (¢/kWh)	(2005$) 4.8	5.2	(2009$) 6.8	6.8
PPA (¢/kWh)	(2011$) 6.7	6.7	(2014$) 9.5	9.4
Revenue Requirements (¢/kWh)	(2011$) 5.8	5.6	(2014$) 8.7	7.9
Revenue Requirements Post GRC Holiday (¢/kWh)	(2021$) 9.4	7.4	(2025$) 13.0	9.5

a) Please provide a copy of the working papers/models/calculations that underpin results shown in the table above, for both the original and superseding BCSs.
b) Did OPG take into account the then most recent provincial electricity demand and supply forecast from the IESO or OPA when it considered whether it should invest a further $600M in the project?
    i. If yes, please provide a copy of the forecast.
    ii. If no, why was electricity demand and supply not considered?
c) Did OPG complete a similar financial analysis for the "cancellation scenario"? Such an analysis could have included the recovery from ratepayers of some portion of the $463M in incurred costs plus up to $100M (as noted in Exh D1-2-1 page 115) in shut down costs plus the cost of replacement energy.
    i. If yes, please provide the financial analysis.
    ii. If no, please complete the table above for the "cancellation" scenario.

Issue 4.5

Are the proposed test period in-service additions for the Niagara Tunnel Project appropriate?

4.5-Staff-25
<u>Ref: Exh D1-2-1</u>
OPG currently estimates that the cost of the Niagara Tunnel Project will be $1.5B and notes that capital costs totalling $1.424M were placed in-service in March 2013.

Please complete the following table. The purpose of the table is to summarize at a high level the cost history and regulatory accounting treatment of the project.

Niagara Tunnel Project

(in millions$)	Pre-2008 actual	2008 actual	2009 actual	2010 actual	2011 actual	2012 actual	2013 budget	2014 Test Year	2015 Test Year	Total 2008-2015
Project Budget Approved/Revised by OPG Board										
Capital Expenditures (actuals)										
Running total accumulated Capital Expenditures										
Gross Plant in-service (o/b)										
Gross Plant additions/deletions										
Gross Plant in-service (c/b)										
Accumulated Depreciation (o/b)										
Accumulated Depreciation (c/b)										
Net Plant in-service (o/b)										
Net Plant in-service (c/b)										
Operating Costs Expensed										
Operating Costs recorded in variance account *										
Rate Base related costs recorded in variance account*										
Variance account Total Balance (o/b)										
Variance account amount cleared										
Variance account Total Balance (c/b)										

Note: * Capacity Refurbishment Variance Account or equivalent
o/b= opening balance, c/b = closing balance

4.5-Staff-26
<u>Ref: Exh D1-2-1 Table 1</u>
Table 1 shows as of June 30, 2013, OPG's estimated spending at completion for each major cost category of the Niagara Tunnel Project including $234.5M for interest. Please provide the interest rates that were used to capitalize "Interest During Construction" for the Niagara Tunnel Project work in progress and the in-service Niagara Tunnel Project.

4.5-Staff-27
<u>Ref: Exh D1-2-1 Table 1</u>
Regarding the capitalization of interest in construction work in progress ("CWIP") for the Niagara Tunnel Project:

a) Please indicate whether the Board's prescribed CWIP accounting interest rates policy for gas utilities, electricity distributors and other rate-regulated entities was applied by OPG.
b) If no to a) above, please provide the reasons and a detailed comparison showing on a monthly basis, the interest rates and interest amounts capitalized by OPG for

"Interest During Construction" compared to the Board's Prescribed Interest Rate (of the DEX Mid Term Corporate Bond Index Yield for the CWIP Account) published on the Board's website and interest amounts based on the prescribed rates from the start of the Niagara Tunnel Project.

4.5-Staff-28

Ref: Exh D1-2-1

For the Niagara Tunnel Project, please provide a detailed summary of all components of the $1.5B in costs for construction work in progress recorded for the Niagara Tunnel Project prior to these costs being recorded in the in-service Niagara Tunnel property, plant and equipment accounts. This summary should be sufficiently detailed to show the year and nature of the cost recorded.

4.5-Staff-29

Ref: Exh D1-2-1

Please indicate whether the salaries and benefits of the OPG staff assigned to the Niagara Tunnel Project or any central or overhead administrative costs were included in capitalized cost (via the CWIP costs) in the in-service Niagara Tunnel property, plant and equipment accounts. If so, please provide the amount.

4.5-Staff-30

Ref: Exh D1-2-1

Please indicate whether the salaries and benefits of the OPG staff assigned to the Niagara Tunnel Project or any central or overhead administrative costs were previously included in the revenue requirement of a previous proceeding. If so, please provide the amounts and relevant proceeding.

Nuclear

Issue 4.7
Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

4.7-Staff-31

Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06)

Regarding the Darlington Refurbishment Project:

a) What were the assumptions used for interest and escalation in the LUEC calculation?
b) Is it correct to assume that the forecasted costs contained in the BCS dated November 14, 2013 are based on better and/or more defined plans? If so, to what extent has the "contingency "component of the forecast declined (as a proportion) compared to the contingency amounts included in the Preliminary Release Business Case dated November 13, 2009?

c) At page 8, Table 1 indicates that the Refurbishment window is now 108 months versus 88 months which was the basis for the BCS of November 13, 2009 (Table on page 6 of Attachment 4 to Exhibit D2-2-1 of EB-2010-0008). To what extent, and quantify if possible, does this impact the LUEC calculation? If there is no impact on the LUEC calculation, please explain why.
d) The BCS at page 3 states that it is OPG Management's assessment that the refurbishment of the Darlington Station would also be competitive with the recently completed refurbishment of Bruce Units 1 and 2. Based on the Auditor General's 2007 assessment of the price being received by Bruce Power for the output of Bruce Units 1 and 2, management estimates the LUEC for those units at approximately 8.5 ¢/kWh (2013$). Please describe the underlying information and assumptions OPG made in preparing this LUEC calculation.

4.7-Staff-32

Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) page 40

Regarding unit life, the BCS states that post-refurbishment, the life of each unit was assumed to be nominally 30 calendar years. It was derived from the current design life of pressure tubes of 24 effective full power years (210,000 EFPH) with recognition that, given the knowledge gained about pressure tube degradation mechanisms, future pressure tubes will likely be designed and operated to achieve longer service lives. Thirty calendar years, with an assumed 88% capability factor translates into a pressure tube life of approximately 26 effective full power years (approx. 231,000 EFPH).

a) What confidence does OPG have in the acceptance of 231,000 EFPH as the design basis of the pressure tubes for the DRP?
b) What is the impact of a 210,000 EFPH versus 231,000 EFPH pressure tube operating life in the calculation of LUEC in terms of pressure tube life and ACF?

4.7-Staff-33

Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) pages 16-17

a) Is it correct that Fuel Channel Life Extension Project is necessary to enable a strategic schedule that has the refurbishment starting in October 2016 and the overlap between units two and one removed?
b) What is the impact on DRP cost and LUEC if the goal of achieving high confidence and CNSC approval for 235,000 EFPH fuel channel life is not successful?
c) In the case that Darlington Units cannot be safely operated to as high as 235,000 EFPH, how would OPG account for associated impacts of a modified schedule in its commercial strategy and contracts with its prime contractors?

4.7-Staff-34

Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) page 40

On November 17, 2011, OPG's Board of Directors approved the revised overall project timeline, the updated Program Release Strategy incorporating an October 2015 Release Quality Estimate (revised from October 2014) in order to incorporate tool testing results from the Re-tube and Feeder Replacement project), and Management's recommendation to move to the Detailed Planning Phase including a partial release of $436 Million.

a) What is the impact of this delay in the availability of Release Quality Estimates in the downstream milestones such as securing project financing, release of contracts to start outage preparations for the first unit?
b) What is the potential impact on Unit 2 refurbishment start date?

4.7-Staff-35

<u>Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) pages 16-17</u>

The BCS indicates that the recommended alternative mitigates risk to the execution of the refurbishment of the first two units; as there would be no overlapping execution periods. This alternative also provides additional time for lessons learned on the first unit to be applied to subsequent units. By extending the overall outage window, this alternative does result in increased costs of OPG Program Management and Support, by approximately $130 Million, and there are greater challenges with this alternative than with Alternative 2 (overlap of the first two units) in retention and continuity of the trades' staff and potentially some key project staff.

a) Please explain why OPG could not apply lessons learned under the overlapped schedule and reduce the overall outage window given that the cost burden as well as retention and continuity of the trades' staff and potentially some key project staff could be managed more effectively?
b) Are there idle time cost implications associated with this alternative? If so, please quantify and confirm whether or not they are included in the DRP estimated costs.

4.7-Staff-36

<u>Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) page 24 and page 18.</u>

The BCS at page 24 indicates that the DRP is still in Definition Phase, several estimates remain at the conceptual level, several major contracts have not yet been awarded and there have been cost pushes in the Re-tube and Feeder Replacements (R&FR) contract and the Turbine Generator (TG) contract. At page 18 the BCS also states that there is high confidence that the DRP will be less than $10B (2013$), excluding interest and escalation.

Please explain the basis for the high level confidence in DRP cost being less than $10B in (2013$), given that only Class 4 cost and schedule estimates have been completed, the Release Quality Estimate will not be available before October 2015, that the DRP is still in Definition Phase and several estimates remain at the conceptual level.

4.7-Staff-37

<u>Ref: Updated Exh D2-2-1 and Attachment 5 page 2</u>

a) Does the LUEC of 7.9 cents/kWh include capitalized interest and future escalation?
    i. If yes, does "capitalized interest" equate to the carrying costs on the amounts employed to fund the project before it is deemed used and useful and recorded in rate base?

   ii. If this is not the case please explain what capitalized interest refers to.

b) If the 7.9 cents/kWh LUEC does not include interest and escalation, please calculate a LUEC that does include capitalized interest and escalation.
c) Does the LUEC of 7.9 cents include the costs associated with the incremental nuclear waste management obligations associated with the operation of the plant for a further 30 years? If not, please calculate a LUEC that includes capitalized interest, escalation and nuclear waste obligations.
d) Corporate Overheads for Pension and Other Post Employment Benefits are not included in the LUEC.
   i. Please explain why OPG views fixed Corporate Overheads for Pension and Other Post Employment Benefits as independent of the decision to refurbish Darlington, and so are not included in the LUEC.
   ii. Would the Revenue Requirement associated with the DRP include these costs?
   iii. If there were no DRP would labour force levels at OPG increase, drop or remain constant?

4.7-Staff-38

<u>Ref: Updated Exh D2-2-1 Attachment 5</u>

Board staff has prepared the Table below. Please populate the Table. If the "Plus Escalation" scenario is not available, the applicable cells can remain blank.

DRP Overall Cost and LUEC Summary

VERSION (select ≥90% confidence estimate)		Over night		Plus escalation		Plus escalation and interest	
		$B	cents/kWh	$B	cents/kWh	$B	cents/kWh
Preliminary Business Planning Case (EB-2010-0008) [Preliminary Release Business Case (OPG Nov 2009)]	2009$						
* Version referenced in EB-2013-0321 Exh D2-2-1 attachment 5 updated page 2	2009$						
	2013$						
Economic Assessment (OPG BoD Nov 2012) Recommendation for Submission to the BoD/OPG	2009$						
	2010$						
	2012$						
Updated Business Case Summary (OPG BoD Nov 2013 & filed February 6, 2014)	2013$						

* Note : Quote from page 2. "In 2010 Management communicated that project would be less that $10B (2009$) which is equivalent to $10.8B in 2013$, excluding capitalized interest and escalation Quote from EB-2013-0321 Exh D2-2-1 attachment 5 updated page 2

4.7-Staff-39

<u>Ref: Updated Exh D2-2-1 Attachment 5 page 6 Figure 1 & Exh D2-2-1 p12</u>

Please confirm the date that the preliminary planning sub-phase of the Definition phase was completed.

4.7-Staff-40

<u>Ref: Exh D2-2-1 Attachment 5</u>

The Recommendation for Submission to the Board of Directors dated November 15, 2012, states that [OPG] management continues to have a high confidence that the DRP will result in a LUEC of 8.6 cents (2012$) and notes that the economics of the DRP are comparable with Combined Cycle Gas Turbines.

a) Is comparability or cost competiveness vis a vis generation alternatives, a significant criterion that OPG's Board of Directors assesses when it decides to approve or deny a partial or full release of funds during the initiation, definition and execution phases of the DRP?
b) If so, what level of cost or other differences between alternatives would trigger denial of funding?

4.7-Staff-41

Ref: Exh D2-2-1 sections 3.3 and 3.4 Exh N1-1-1 and EB-2010-0008 Exh D2-2-1 page 10 Figure 2.

OPG states "The CNSC issued their assessment of the ISR on July 5, 2013; the assessment concluded that the ISR meets applicable regulatory requirements. OPG is currently in the process of preparing the Integrated Implementation Plan ("IIP") and Licensing Application for the DRP; both will be submitted to the CNSC in late 2013 and the new licence is expected by early 2015." OPG also indicates that "Project definition will be completed in 2015 where release quality estimates will be available for project execution; Project Definition (2010-2015) - Front-end project planning including completion of all regulatory requirements, required Facility and Infrastructure upgrades, tooling, detailed engineering and the development of the project scope, cost, and schedule baseline."

a) Has OPG filed the IIP and Licensing Application with the CNSC? If not, why not? When will OPG file it with the CNSC?
b) Assuming the acceptance of the ISR and the IIP, to what extent will confidence in total costs and economics (LUEC) change in light of reduced regulatory uncertainty and the fact that regulatory scope comprises 78% of total direct costs?
c) Please explain the one year delay in the Release Quantity Estimate. It will now be available in 2015 which is a year later than the date indicated in the EB-2010-0008 proceeding.

4.7-Staff-42

Ref: Exh D2-2-1 Attachment 5, Table C7 (Updated 2014-02-06)

Table C7 shows that 88% was used as the medium confidence (50%) Average Capacity Factor ("ACF") and 83% was used as the high confidence (90%) ACF.

Based on EB-2010-0008, D2-2-1, Attachment 4, Appendix C, Figure 3, future performance of refurbished units appears as the second largest aspect of the LUEC sensitivity where a base ACF of 87% is quoted. As indicated in section 1.2.4 of the same document, this value was based on the consensus arrived by the discussions with senior station personnel and discussions with the NGD Project Team and the Advisory Committee. Also as described in Section 1.2.4 the high confidence ACF of 82% accounts for the station's since-in-service performance as well as risks associated with the implementation of Integrated Asset Management Plan (AMP), inability to maintain a 3-year outage cycle as well as 20-month outages at year 15 post-refurbishment, if necessary, to replace steam generators.

a) What is the basis for increasing both high and medium confidence ACF values by 1%? What is the impact of such an increase on LUEC?
b) Why did OPG use 87% ACF as the base value when performing the sensitivity analysis for LUEC instead of 82% (given that there is no OPEX for a CANDU comparable to DNGS operating at an ACF equivalent to its first 30-year life ACF of 87% for an additional 30-year life)?

4.7-Staff-43

Ref: Exh D2-T2-S1 page 12

The evidence indicates that the Release Quality Estimate for the DRP is now expected a year later, being October 2015. The Board in its EB-2010-0008 Decision (page 71) indicated that "Approval of the expenditures for the test period should not be taken as an acceptance of the business case underlying the entire project. Once the DRP reaches the stage of having a release quality cost estimate the Board expects to examine the reasonableness of proceeding with the project."

a) How soon after October 2015 will OPG update the Board on the release cost estimate and, and the then current business case summary?
b) In the event that there is not an ongoing proceeding or soon to be one at the time of the release quantity estimate, will OPG still file the aforementioned material with the Board for its consideration?

4.7-Staff-44

Ref: Exh N-1-1 Attachment 4 page 4

OPG's 2014-2016 Corporate Business Plan states that "The Darlington refurbishment execution phase (October 2016 to late 2015) reflects un-lapping of the first and second units."

a) Have any of the DRP documents filed with the Board since April 2008 reflected un-lapping between units? If the answer is no, why was un-lapping not identified for consideration in the previous plans?
b) During which phase/sub-phase (Definition/preliminary planning or Definition/detailed planning), did OPG decide to "un-lap" the work on the units?
c) What changes led to the recent conclusion that it was preferable to un-lap work on the first two units?
d) Does un-lapping increase or decrease OPG's risk regarding costs and timely execution? Please elaborate on how ratepayers are better served from this approach.
e) How does un-lapping affect the estimate of the total DRP cost?

4.7-Staff-45

Ref: Exh N-1-1 Attachment 4 page 5

OPG's 2014-2016 Corporate Business Plan states that, "A long-term rate smoothing strategy to address nuclear rate impacts during the Darlington refurbishment is assumed to commence in 2016, subject to OEB acceptance. A regulatory asset of ~$150 M is recognized in 2016 related to deferral of nuclear rate impacts, for subsequent recovery."

Please describe the strategy that is assumed to commence in 2016 and the nature of the regulatory asset.

Issue 4.8
Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

4.8-Staff-46

Ref: Exh D2-1-3 Table 1

The Standby Generator Governor Upgrade project (line 6) shows a Feb 2013 "final in-service date" (col. f) and project costs of $23.3 million. Please explain why no dollars are shown for "in-service" 2013 or 2014 or 2015 (cols.k,l,m)

Issue 4.9
Are the proposed test period in-service additions for the Darlington Refurbishment Project appropriate?

4.9-Staff-47

Ref: Exh D2-2-1 & Exh N1-1-1 Updated D2-2-1 Attachment 5 & Feb 6, 2014 Cover Letter from OPG.

OPG notes at page 13 of Exh D2-2-1, that "In November 2013, Management will update the overall Business Case for the DRP and present it to OPG's Board of Directors for approval. Management will also request a release of funds to complete the Definition Phase, projected in the amount of $857M in 2014 and $650M in 2015." On December 6, 2013 OPG filed its 2014-2016 Corporate Business Plan, dated November 14, 2013, which it had presented to its Board of Directors. On February 6, 2014 OPG filed an updated Business Case Summary for the DRP, including a cover letter which stated that the Updated Business Case Summary was approved by OPG's Board of Directors in November 2013.

a) Did the Board of Directors approve without qualification the Corporate Business Plan dated November 14, 2013?
b) Are the elements (e.g. costs, schedule) in the DRP Updated Business Case, exactly the same as those presented in the 2014-2016 Corporate Business Plan regarding the DRP? If not, please list and explain the differences.
c) Please list the material differences between the Updated Business Case Summary filed on Feb 6, 2014 and the Recommendation For Submission to the Board of Directors (dated November 15, 2012) it replaced.

d) Are there any differences between the Updated Business Case Summary approved by the Board of Directors in November 2013 and the one filed with the Board on February 6, 2014?
   i. If the two versions are the same, please identify and explain the cause for the delay in filing the Updated Business Case Summary with the OEB. In your response please address OPG's stated commitment that it would be filing its DRP Updated Business Case in late 2013.
   ii. If the Updated Business Case Summary approved by the OPG's Board of Directors is not the same as the one filed on February 6, 2014, please identify and explain the differences.

4.9-Staff-48

Ref: Exh D2-2-1 page 22-23

OPG states that "Some projects [DRP related] arising from pre-requisite work done in the Definition Phase….. will be placed in service and included in rate base as soon as they are used or useful to OPG, and as such will be depreciated over their useful lives. These projects are expected to remain useful to OPG's current or future nuclear operations independent of whether the DRP is completed."

a) Please confirm that the DRP related in-service additions to rate base are $5.0M in 2012, $104.2M in 2013, $18.M7 in 2014 and $209.4M in 2015.
b) Please populate the table below. Please confirm that the projects listed in the table below are those identified by OPG as projects, including three safety improvements projects/DRP EA, which will be completed and placed in service in the test period. If this is an inaccurate summary please amend the table accordingly.

DRP projects wholly or partially in service in the test period ($millions)	In service year	Projected Total Capital Expenditure	Amount in 2014 Rate Base	Amount in 2015 Rate Base	Depreciation in 2014 Rev Req	Depreciation in 2015 Rev Req	Amount recorded in Capacity Refurb Variance Acct (Dec. 2013) *
Darlington Energy Complex							
Water and Sewer Project							
Heavy Water Storage & Drum Handling Facility							
Darlington Operations Support Building Refurb.							
Auxiliary Heating System							
Electrical Power Distribution System							
Powerhouse Steam Venting System							
Third Emergency Power Generator Project							
Container Venting System Project.							
TOTAL							

***** Note: Account records vaiances between actual capital and non capital and firm capital commintment incurred for the DRP and the corresponding forecasts reflected in the revenue requirment approved by the OEB

c) Please provide the rationale for treating these projects as part of the DRP initiative even though the evidence states that the projects are expected to remain useful to OPG independent of whether the DRP is completed. In your response please respond to the question: "Would these projects proceed had there not been a DRP?"

d) Assume that the Water and Sewer Project went ahead regardless of the DRP, and that costs were incurred in 2012 and 2013 and portions of the Water and Sewer Project were put into service in 2012 and 2013. Would OPG have proposed recovery in the 2014 and 2015 payment amounts for the related capital carrying costs on 2012 and 2013 rate base and for the associated depreciation expense? If so, please provide the regulatory accounting principle underpinning this treatment.

4.9-Staff-49

Ref: Exh D2-2-1, Attachment 5 and Updated Attachment 5

OPG states that the DRP is a program to enable the replacement of life-limiting critical components, the completion of upgrades to meet current regulatory requirements and the rehabilitation of components. This will extend the life of Darlington by 30 years, from 2020 to 2050.

a) Is the following description of the timing of the Initiation, Definition and Execution phases accurate? The Initiation phase was completed in December 2009 with the Board of Director's approval to proceed with the project. The preliminary planning sub-phase of the Definition phase was competed in November 2011 with Board of Directors approval to proceed. The detailed planning sub-phase of the Definition phase commenced in January 2012 and is expected to conclude in 2015. The Execution Phase commences 2016 and concludes 2024.
b) Board staff has reproduced and added a few lines to a portion of Table 3 (DRP Overall Project Estimate) found at Exhibit D2-2-1 Attachment 5 (titled "Recommendation for Submission to the Board of Directors and includes " Appendix 1- Update on the Darlington Refurbishment Project Economics" dated November 15, 2012) .

		(a)	(b)	(c)	(d)
ln	**Darlington Refurbishment Project-Components (in millions$)**	**Refurb (Core)**	**O&M Support (OM&A)**	**Value Enhancing**	**Total**
1	Retube and Feeder Replacement				
2	Fuel Handling				
3	Steam Generators				
4	Turbine Generators				
5	**Sub sub- total Major Contracts**				
6	Balance of Plant				
7	Operations/Maintenance Support				
8	Waste Management				
9	New Fuel				
10	Infrastruture Projects				
11	**Total Direct Work**				
12					
13	Program Support and Oversight				
14	Regulatory				
15	**Total Support**				
16					
17	**Contingency**				
18					
19	Interest				
20	Escalation				
21	**Total Interest & Escalaltion**				
22					
23	**(Provision) Retube Waste Containers**				
24					
25	Infrastucture Projects - Station- CS				
26	Contingency				
27	Interest				
28	Escalation				
29	**Subtotal F & IP CS Projects**				
30					
31	**GRAND TOTAL**				

Please complete the table and reflect the following: The dollar amounts should be consistent with the total cost forecast/estimate found in the Updated Business Case Summary dated November 14, 2013 and filed with the Board on February 6, 2014. Breakout the dollar amount in line 5 into its component parts, lines 1-4. At Exh D2-2-1 page 21 “Balance of Plant” is described as remaining work to be performed by OPG that is not included in the Contracts for Major Work Package and is broken into 6 work groups: Reactor, Conventional Systems, Common Systems, Pre-refurbishment, Safety & Controls and Special. If possible/practical, please add the necessary rows to capture this cost information for these work groups.

c) Are the costs associated with the following projects [Darlington Energy Complex, Water and Sewer Project, Heavy Water Storage and Drum Handling Facility, Darlington Operations Support Building Refurbishment, Auxiliary Heating System and Electrical Power Distribution System, Powerhouse Steam Venting System, Emergency Power Generator and Containing Venting System] included in the table above?
    i. If yes please identify the line in which they are captured.

ii. If not, please amend the table, as appropriate, to incorporate these costs.

d) How much of the total (row 31) has already been recovered through historical and proposed for 2014-15 prescribed payment amounts, including any disposition of deferral/variance accounts?

4.9-Staff-50

Ref: Exh D2-T2-S1

OPG indicates that it developed an overall Commercial Strategy and separate Contracting Strategies for all major project work packages.

Using the information from the completed IR above [4.9-Staff-49] please complete the table below. The table assumes that the major work projects are not yet in execution phase, but are in one of the two sub-phases of the Definition Phase (either preliminary planning or detailed planning). In the projected cost column, please show the latest projected costs for the work project. In the percentage column, please indicate the "accuracy" range for the project cost associated with the sub-phase for the work project. In the appropriate sub-phase column briefly state the pricing/$ risk mitigating arrangement e.g. Fixed/Firm Price or Guaranteed Maximum or Target Price or Cost Reimbursable.

If any of the Facility & Infrastructure projects are still in the Definition Phase please add them to the table.

source: Exh D2-2-1 Attachment 6

DRP Work Packages/ Other Components and Overall Commercial Stratgy (Multi Prime Contractor) and Contracting Strategies					
Estimated costs and current phase and % estimation accuracy and approach to cost vs estimate risk management					
	Latest Projected (Cost $M)	**Definition Phase/preliminary planning sub-phase)**		**Definition Phase (detailed planning sub-phase)**	
		%		%	
Contracts for Major Work Projects					
Retube and Feeder Replacement					
Fuel Handling					
Steam Generators					
Turbine Generators					
Subtotal major contracts					
Balance of Plant					
Reactor Systems					
Conventional Systems					
Common Systems					
Pre-refurbishment					
Safety & Controls					
Special Groups					

Issue 4.10

Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

4.10-Staff-51

Ref: Exh D2-2-1 page 23 & Attachment 8.-1

In Exh D2-2-1 OPG refers to the Darlington Energy Complex ("DEC") while Attachment 8-1 is the business case for a project titled "Darlington Refurbishment Complex (DRC) at the Clarington Energy Center". Are these one and the same?

4.10-Staff-52

Ref: Exh D2-1-2 Section 3.1 page 2

OPG states that most projects to be undertaken in the test period are sustaining projects, or projects to sustain and/or improve plant reliability at both Darlington and Pickering. They include expenditures on systems and components approaching their end of life, or for which replacement parts are no longer readily available.

a) Are any of these projects directly or indirectly related to the DRP? If so please identify which ones and their total cost in 2014 and 2015.
b) Please describe the transition plan OPG has in place to ensure that there is ongoing coordination of the timing, approval and execution of sustaining and plant reliability projects with the DRP related investments.
c) Please provide examples of where a planned Darlington sustaining or reliability project has been deferred until after refurbishment has taken place.

4.10-Staff-53

Ref: Exh D2-1-2 section 1.0 & section 3 & Table

OPG states that "As part of its 2014-2016 Business Planning process, OPG is reassessing its 2015 project portfolio budget and anticipates increases in the project portfolio to address recent emerging requirements for new project expenditures" and that it "…intends to make capital investments associated with critical equipment at Darlington and Pickering in 2015 to meet regulatory requirements as well as improve ongoing and future reliability as Darlington units are taken offline for refurbishment."

a) Please provide a brief description of the regulatory requirements underpinning these investments.
b) What will these aforementioned investments total for each of Darlington and Pickering and what amount, if any, is reflected in the 2015 rate base?
c) Are any or all of these costs reflected in OPG's 2014-2016 Business Plan (filed with the Board on December 6, 2013) and/or updated DRP BCS (filed with the Board on February 6, 2014)?
d) Would these costs be incurred in 2015 if there were no DRP?
e) Will the unallocated portfolio budgets, of $128.0M in 2014 and $109.2M in 2015, fund these emerging needs? If not, please describe the assessment or needs review that OPG undertook/will undertake to determine that the unallocated portfolio budget is inadequate.
f) Are the unallocated portfolio budgets referenced in (e) reflected in 2014 or 2015 rate base?

4.10-Staff-54
Ref: Exh D2-2-1 Attachment 5 (Updated 2014-02-06) page 11
The BCS indicates the following. The second work area of Fuel Handling is the refurbishment of the Fuel Handling System. The work for the Fuel Handling System has been divided into 6 work packages. As part of the 2013 Darlington Scope Review, a portion of the scope has been transferred to the Darlington Station to be performed as part of the station's Fuel Handling Reliability project. The balance of the scope will be awarded in late 2013 and early 2014.

Under which table in D2-1-3 and which Project number is the portion of the scope that has been transferred?

4.10-Staff-55
Ref: Updated Exh D2-2-1 and Attachment 5 page 9
The Updated Business Case Summary notes that OPG continues to discuss with the province the need for greater assurance of cost recovery and has suggested regulatory changes to facilitate this. Please describe the regulatory changes which OPG has recommended.

4.10-Staff-56
Ref: Exh D2-1-2 Table 1 & Exh D2-2-1 Table 1
Board staff prepared the table below for nuclear capital expenditures for the period 2010-2015.

(in millons$)							
Nuclear Capital Expenditure Summary	**2010 actual**	**2011 actual**	**2012 actual**	**2013 budget**	**2014 forecast**	**2015 forecast**	**Total 2010-2015**
Operations Capital	$ 178.3	$ 148.2	$ 161.4	$ 170.2	$ 196.3	$ 143.9	$ 998.3
Darlington Refurbishment	$ 32.6	$ 91.0	$ 232.5	$ 529.8	$ 837.4	$ 631.8	$ 2,355.1
Total Nuclear Capital	$ 210.9	$ 239.2	$ 393.9	$ 700.0	$ 1,033.7	$ 775.7	$ 3,353.4
source: Exh D2-1-2 Table 1 & Exh D2-2-1 Table 1							

Based on the latest DRP business plan, what percentage of the DRP total capital expenditures is projected to have been spent by the end of 2015?

Issue 4.11
Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

4.11-Staff-57
Ref: Exh D2-2-1 section 6.0
The Commercial Strategy selected by OPG is a multi-prime contractor model in which there is more than one prime contractor working on the project.

a) Does OPG have experience in using a multi-prime contractor model to manage a large and complex project similar to what is planned for Darlington's refurbishment? If so, for what major projects?
b) How are the risks associated with multi-prime contractor approach accounted for in the overall project cost?
c) Does OPG have a strategy at the prime-contractor level that deals with interface issues, potential conflicts and mitigating actions to resolve them?

Issue 4.12
Does OPG's nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario's Long Term Energy Plan issued on December 2, 2013?

4.12-Staff-58
Ref: Exh D2-1-2 and Updated D2-2-1 Attachment 5, Long-Term Energy Plan (December 2, 2013)
On December 2, 2013 the Ministry of Energy released the Long Term Energy Plan ("LTEP") for the Province of Ontario. The LTEP noted that:

> The nuclear refurbishment process will adhere to the following principles:
> 1. Minimize commercial risk on the part of ratepayers and government;
> 2. Mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
> 3. Entrench appropriate and realistic off-ramps and scoping;
> 4. Hold private sector operator accountable to the nuclear refurbishment schedule and price;
> 5. Require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
> 6. Make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
> 7. Take smaller initial steps to ensure there is opportunity to incorporate lessons learned from refurbishment including collaboration by operators.

On December 5, 2013 OPG filed an update to its evidence, including OPG's 2014-2016 Business Plan (portions redacted) which was presented to its Board of Directors on November 14, 2013. On February 6, 2014 OPG filed an updated DRP Business Case Summary.

a) Is the 2014-2016 Business Plan consistent with all of the principles set out in the LTEP?
    i. If so, please demonstrate how the Business Plan puts each of the principles into action.
    ii. If not, please explain why OPG did not reflect these principles in the Business Plan.

b) Does the updated DRP Business Case Summary, including scope, cost schedule and project management approach, conform to the principles set out in the LTEP?
    i. If so, please demonstrate how the Business Plan puts each of the principles into action.
    ii. If not, please explain why OPG did not reflect these principles in the Updated Business Case Summary.
c) Please prepare a LUEC calculation which reflects the following scenario: at the completion of the refurbishment of Unit 2, actual refurbishment costs for Unit 2 are $0.7B in excess of budget. As a result, it is decided to cancel the refurbishment of Units 1, 3 and 4. What would the LUEC be for the production for a refurbished Unit 2 (i.e. all DRP costs recovered through only Unit 2 production)?

PRODUCTION FORECASTS

Regulated Hydroelectric

Issue 5.1
Is the proposed regulated hydroelectric production forecast appropriate?

5.1-Staff-59
Ref: Exh E1-1-2 page 1 and Exh N1-1-1 page 16
Total production from the Niagara Plant Group (“NPG”) and Saunders is forecast to increase by 5.2 percent (1.0 TWh) primarily due to higher flows forecast for the Niagara and St. Lawrence Rivers in the 2015 Plan.

a) In the last 10 years how many times has the actual annual production from NPG and Saunders increased by 5% or more year-to-year?
b) For the last 10 years what has been the deviation of actual annual production from forecast production in both absolute and percentage terms?
c) What are the specific meteorological factors that lead to the forecast of increased flow rates for the Niagara and St. Lawrence Rivers?
d) Precipitation and evaporation are specifically mentioned as significant factors affecting the availability of water. Over the last 10 years what has been the trend change in both of these factors?

5.1-Staff-60
Ref: Exh E1-1-1 pages 2 - 8
Twenty-seven of the newly regulated facilities use average historical production as their production forecast.

a) Is this an average monthly production forecast for each station or for the aggregate output of all 27 stations?
b) How many observations are included in the average calculation? Is the calculation a simple average or a weighted average that would give greater (or lesser) weight to more recent observations?

c) In preparing the production forecasts for these 27 stations, does OPG apply any adjustments to the monthly averages of actual production to account for trends in meteorological conditions?

Issue 5.3
Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

5.3-Staff-61
Ref: Exh E1-2-1 pages 8&9
OPG states: "When SBG spill cannot be avoided, because the water cannot be time-shifted or stored, it is irrevocably lost. As a result, the monthly average production falls. The SBG spill, which lowers the monthly average production, is compensated for by an entry in the SBG variance account. However, the resulting production profile, reduced by the SBG spill volume also generates incentive payments under the HIM. This is an unintended consequence of interaction between the HIM and SBG Variance Account."

The problem of "unintended" compensation appears to be "double counting" for foregone generation from SBG conditions arising when the monthly production average is reduced by the volume of SBG.

a) To negate this impact, is it not possible to add in the amount of SBG generation foregone to the actual production to get an "average monthly production compensated for SBG" for operating the HIM?
b) Is there a qualitative or quantitative difference between the adjustment above and OPG's proposal: "…induced incentive revenues arising from SBG-related spill should be removed from the SBG Variance Account."?

5.3-Staff-62
Ref: Exh E1-2-1 page 13
OPG proposes to eliminate the revenue requirement adjustment associated with the incentive revenues, claiming that the value to the customer, i.e., reduced payments to natural gas generators and higher export revenues, accrue to consumers simultaneously with the incentive payments accruing to OPG.

The benefits that OPG identifies are "general system benefits" that arise from the impact on the market of incremental PGS generation being available during peak, or higher, demand periods. This is not the same as increased revenues arising from selling incremental energy above a threshold of average generation that is shifted from low price periods to higher price periods. These are real revenues, incremental to the general system impacts, and a portion should be returned to consumers by reducing OPG's revenue requirement in the future.

OPGs regulated hydroelectric assets operate in a price guaranteed, low risk environment. The HIM is intended to encourage OPG to operate the PGS as if it was transacting in an open, competitive market with corresponding risks and rewards. OPG risks and loses nothing if they miscalculate and operate the PGS inappropriately, yet consumers will lose the potential “general system benefits” identified by OPG.

In exchange for the security of a guaranteed price, is it not appropriate that OPG share the direct rewards of operating outside that low risk environment by a reduced revenue requirement in the future? If not, please explain why not.

Issue 5.4
Is the proposed new incentive mechanism appropriate?

5.4-Staff-63
Ref: Exh E1-2-1
OPG proposes that the enhanced Hydroelectric Incentive Mechanism (“eHIM”) apply to the existing hydroelectric facilities plus the newly regulated hydroelectric facilities.

a) The HIM is associated with the PGS facilities operating in tandem with the SAB GS in that water can be diverted for higher value generation. How does the incentive work for run-of-river units, i.e., Saunders, which is one of the originally prescribed hydroelectric facilities?
b) What is OPG proposing for the newly regulated hydroelectric facilities? Can the newly regulated hydroelectric dams store water in the same way that the PGS can? If so, what is the potential for operating the newly regulated units in this manner?
c) Does OPG intend that all of the newly regulated hydroelectric facilities be considered as potential participants in the eHIM, or just the 21 units listed in Exh E1-1-1 Appendix 1?

Nuclear

Issue 5.5
Is the proposed nuclear production forecast appropriate?

5.5-Staff-64
Ref: Exh N1-1-1 pages 12 - 13
OPG submitted a revised production forecast (2014-2016 Business Plan, dated November 14, 2013) with significant reductions in production for 2014 (-0.6 TWh) and 2015 (-2.0 TWh) compared to the originally filed forecast (2013-2015 Business Plan, dated May 16, 2013).

These reductions are entirely the result of an increase in planned outage days; a 10.6% increase in 2014 and 22.9% increase in 2015. OPG’s explanation for these increases notes the complexity of planned maintenance outages and the historical performance of nine consecutive years of actual generation being lower than forecast.

a) What did OPG specifically discover in the six month period between these two forecasts to justify such a significant increase in planned outages?

b) Why make these adjustments now, all at once, if the evidence over the previous nine years indicated a systemic bias for over forecasting production?

5.5-Staff-65

Ref: Exh N1-1-1 page 14

OPG lists the detailed changes in the Pickering N.G.S. planned outage schedule.

a) Why was the 2013 Unit 4 planned outage deferred to January 2014?
b) Board staff notes that this deferral cascades into other planned outages for 2015 and 2016. What is the nature of the “additional scope” that resulted in an additional seven days of outage in 2014?
c) An additional 28 day 2015 mid-cycle reduction was added to the 2014-2016 BP.

   OPG notes that “…starting in 2012, OPG began implementing short duration, mid-cycle planned outages (i.e., an additional planned outage within the two year cycle) for Pickering Units 1 and 4 to focus on preventative maintenance and to lessen the risk of future forced outages thereby improving reliability and reducing the FLR.”

   i. Board staff notes that OPG indicates that this practice started in 2012. Why was this practice not included in the 2013-2015 Business Plan production forecast?
   ii. Is there a material difference between outage days attributed to FLR versus planned outages? If so, describe these differences and how the materiality is calculated.
   iii. Is one form of outage more costly to accommodate than the other? If so, based on previous experience with FLRs and planned outages what is the net difference in scalable costs, i.e., costs per day of outage?
   iv. Is there a performance metric for FLRs that is a component for determining individual compensation or bonuses for OPG staff? Is there a comparable performance metric for achieving, or exceeding, the planned outage schedule?

d) Based on historical performance over the 2005 to 2013 period that showed an average annual forced extension of 82.5 days to planned outages at Pickering, OPG increased allowances for planned outages by a total of 28.6 days over the two year test period. How did OPG determine that an average annual outage of 14.3 days was justified when average annual forced extension of outages over the selected comparison period are nearly six times that rate?

5.5-Staff-66

Ref: Exh N1-1-1 pages 15-23

The revised Darlington production forecast reduced output by 1.6 TWh total for 2014-15 compared to the 2013-2015 Business Plan forecast.

0.28 TWh of this lower production is related to higher lake water temperatures that reduce condenser efficiency.

a) How are these lake water temperatures forecast?
b) Is there a historical correlation to lake water temperatures and Niagara and St. Lawrence River flows? If so, what is that correlation?

5.5-Staff-67

Ref: Exh N1-1-1 pages 15-23

Planned outage days for Darlington are increased by a total of 61.9 days, with 93% (57.6 days) of the outage occurring in 2015. 39 additional planned outage days are added because of an increase in the vacuum building outage ("VBO") scope.

a) What factors were involved in changing the planning for VBO outages from the 2013-2015 Business Plan to the current plan?
b) In Exh E2-1-1, page 6, OPG states that it is seeking regulatory approval (presumably from the CNSC) to eliminate the station containment outages going forward and that this strategy of moving forward the VBO to 2015 is part of that regulatory plan.
    i. How critical is CNSC approval to the outage plans?
    ii. When will OPG know if they are successful with this strategy?
    iii. If regulatory approval is not obtained, what is OPG's plan to accommodate this scenario?
c) On page 15, the evidence contains the following statement: "….the 2015 VBO eliminates the need for the 2021 VBO, reducing the complexity and resource demands during the Darlington Refurbishment Project." To support this statement, did OPG prepare any analysis of the cost and benefits of moving the VBO forward to 2015?

OPERATING COSTS

Regulated Hydroelectric

Issue 6.1
Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.1-Staff-68

Ref: F1-2-1, Table 2

Under hydroelectric base OM&A, the application notes that the Niagara Plant Group 2011 actual costs include an extraordinary credit of $19M related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS). That credit represented over 1/3 of the total Base OM&A approved by the Board for the Niagara Plant Group as the Board approved $53.5M and actual costs were $33.7M.

a) Please identify if that $19M was reallocated for other purposes. If so, please explain.

b) Does OPG foresee the potential for a similar extraordinary credit in the current test period?

6.1-Staff-69
Ref: F1-1-1, Table 2
Please refer to the table below prepared by Board staff.

Newly Regulated Hydroelectric							
(in millions)	2010 Actual	2011 Actual	2012 Acutal	2013 Budget	2014 Proposed	2015 Proposed	Average (2010-13)
Base OM&A	100.0	106.0	102.9	113.2	113.4	113.7	105.5
Project OM&A	39.8	21.6	20.3	16.0	24.5	32.1	24.4
Allocation of Corporate Costs	31.4	32.3	36.6	38.8	42.1	39.6	34.8
Allocation of Centrally Held Costs	19.0	25.1	33.1	47.2	49.6	48.7	31.1
Asset Service Fee	3.6	3.4	3.3	3.1	2.9	3.0	3.4
TOTAL	**193.8**	**188.4**	**196.2**	**218.3**	**232.5**	**237.1**	199.2

a) Please confirm that OM&A expense for the newly regulated hydroelectric plants averaged about $199.2M annually between 2010 and 2013.
b) What material changes underpin the $35M or 17% increase, as compared to the historical average, in OM&A expense in 2014 and 2015?

6.1-Staff-70
Ref: Exh F1-3-1 (Table 1), F1-3-2
As noted in the evidence, project OM&A costs for Newly Regulated Hydroelectric decline in the 2013 bridge year and that is followed by a significant increase in the test years -- increases by 100% from $16 million to $32.1 million by 2015. The application indicates the start of 2 unit overhauls in the Central and Northeast Hydro Plant Groups – Lower Notch GS and Otto Holden GS (as well as SAB PGS) – are the primary contributors to that increase and that there were no unit overhauls in 2013. Please explain why those unit overhauls are being initiated in the test period and none were undertaken in the bridge year.

6.1-Staff-71
Ref: Exh F1-5-1, Decision of the Court of Appeal for Ontario Docket C55602, C55641, C55633
This exhibit provides a listing of purchased services – regulated hydroelectric OM&A contracts for 16 vendors.

Please identify every expense that was committed to prior to the test period. Please also provide all of the information that OPG relied on when OPG committed to each of those expenses including the cost that has been committed for each of those expenses in the test years and the associated total cost for each expense. Please provide that information broken down by year, including before and after the test period, where applicable.

6.1-Staff-72

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

The Auditor General's Report includes a number of findings associated with staff training. With respect to Hydro/Thermal Training, the findings included that there is no regulatory oversight (unlike nuclear) and that hydro/thermal training has never been evaluated by OPG or third parties. Further, 30% of the courses OPG requires had not been completed in 2012. The findings noted that last-minute cancellations of scheduled courses have been an issue in every year going back to prior to 2010 when OPG's Hydro/Thermal Training Decision Making Committee raised concerns and, recommended that plant managers should try to reduce them to optimize the use of training resources.

OPG's response in the Auditor General's Report stated that OPG will continue with its review of the nature, timing and delivery methods of mandatory training requirements for hydro/thermal staff. In OPG's Backgrounder that identifies actions OPG is taking to address the findings, there is no mention of any actions related to training.

a) When does OPG intend to complete a review of the Hydro/Thermal training program, given the Committee noted above began raising concerns in 2010?
b) Please provide further discussion on any actions that OPG is taking, or is planning to take, to improve cost effectiveness and success rates of its hydro/thermal training programs.

Issue 6.2
Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the regulated hydroelectric facilities reasonable?

6.2-Staff-73

Ref: Exh F1-1-1, page 9

Chart 2c in the application identifies the OM&A unit energy cost ("UEC") targets for 2010 – 2015 for the regulated hydroelectric stations. Please explain why the UEC for the Central Hydro stations is about 5 fold higher than the other newly regulated stations.

6.2-Staff-74

Ref: Exh F1-1-1, Chart 1b and Chart 2b

Chart 1b summarizes the target and actual Equivalent Forced Outage Rate ("EFOR") for the hydroelectric plants for the period 2010-2012. Chart 2b summarizes targets for 2013-2015.

a) What are the actual EFOR for 2013?
b) Why are the 2013-2015 EFOR targets for SAB 1, SAB PGS, RH Saunders and Northeast PG higher than the 2012 targets?

6.2-Staff-75
Ref: Exh F1-1-1, page 18
The results of the Navigant Consulting OM&A unit energy cost benchmarking study are provided in Chart 4. The application explains why the SAB PGS unit energy costs are much higher than OPG's other hydroelectric stations. However, the chart shows that the SAB PGS is in the 4th quartile for each year and it is benchmarked relative to other PGS facilities. The unit energy cost also increased from $65.2/MWh to $128.2/MWh over the 3 year period.

a) Please explain why SAB PGS is consistently in the lowest quartile amongst PGS plants.
b) Please also explain why the unit energy cost for SAB PGS almost doubled over the 3 year period.
c) Please identify the unit energy cost for 2013.

Nuclear

Issue 6.3
Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.3-Staff-76
Ref: Exh F2-5-1, ExhF2-6-1, Decision of the Court of Appeal for Ontario Docket C55602, C55641, C55633
Please identify every expense that was committed to prior to the test period. Please also provide all of the information that OPG relied on when OPG committed to each of those expenses including the cost that has been committed for each of those expenses in the test years and the associated total cost for each expense. Please provide that information broken down by year, including before and after the test period, where applicable.

6.3-Staff-77
Ref: Exh F2-3-3 Attachment 1 Tab 11 – Fuel Life Extension Project, F2-3-3 Table 1 and Table 5
On February 6, 2014, OPG updated its evidence, including the Business Case Summary ("BCS") for project 10-800014 Fuel Life Extension Project (F2-3-3 Attachment 1 Tab 11).

a) Please describe how this project is separate from project 10-62444 Fuel Life Channel Management. Is this new extension project contingent on the work done on or the outcomes of the earlier project?
b) Please confirm that the costs for the Fuel Life Channel Management and Fuel Life Extension projects are entirely separate.

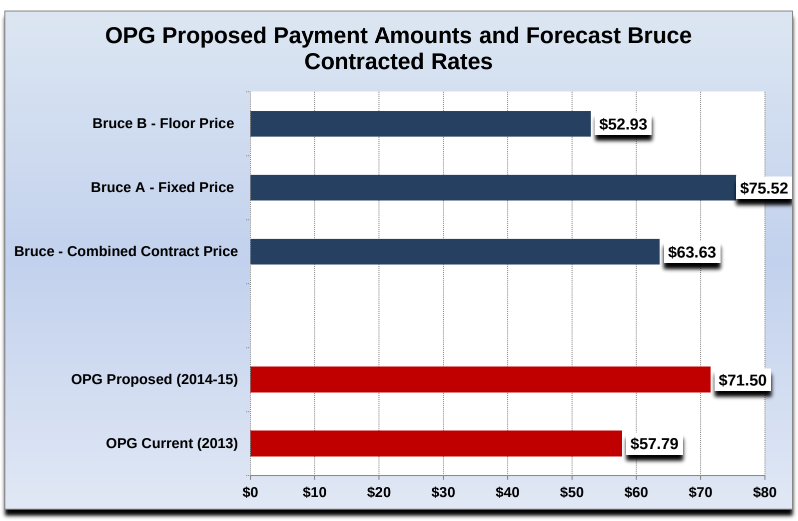
c) Please update F2-3-3 Table 1 OM&A Project Listing – Nuclear Projects ≥ $20M Total Project Cost to include project 10-800014 Fuel Life Extension Project. Also, please insert a column between 2013 Budget and 2014 Plan and show 2013 actuals (audited or unaudited) for each project.
d) Please update F2-3-3 Table 5 to include project 10-800014 Fuel Life Extension Project.

6.3-Staff-78

Ref: Exh A1-3-1 (page 4-5); N1-1-1 (Chart 11)

The application notes it is important to consider OPG's payment amounts within the context of the greater Ontario electricity industry as a whole. For the first six months of 2013, OPG's average revenue was 5.6 cents/kWh, whereas the average revenue for all other electricity generators was 10.1 cents/kWh.

a) Please explain why OPG believes it is appropriate and relevant to compare its payment amounts to those of non-nuclear generators including those with OPA FIT contracts such as wind and solar generators?
b) For the purpose of this application, would it not be also be appropriate to compare OPG's proposed nuclear payment amounts against other similar nuclear plants, such as Bruce Power's contracted rates?
c) The chart below shows such a comparison with Bruce Power's contacted rates adjusted (fuel and inflation) based on the forecast in the Board's most recent RPP Price Report. Bruce Power's forecast combined contract rate (Bruce A and Bruce B) is $63.63/MWh and OPG's proposed payment amount (including riders) is $71.50/MWh. Please provide OPG's views on why its forecasted 2014-2015 proposed payment amounts for Pickering and Darlington are more than 10% higher than the Bruce combined contract price.



6.3-Staff-79

Ref: Exh F2-1-1 (Table 2), A1-3-2 (Chart 2)

A comparison of Nuclear Operations OM&A costs (Base, Project and Outage OM&A) is provided in a manner to reflect the Board Adjustments for 2011 and 2012 consisting of the reductions in nuclear compensation costs of $55M (2011) and $90M (2012), which is identified in A1-3-2 as a Nuclear Deficiency in the "Other" category. Board staff wants to confirm that its understanding of Table 2 is correct. That is, relative to the Board approved amounts following those adjustments, OPG's actual costs for 2011 were $85.4M higher and actual costs for 2012 were $38M lower. Is that understanding correct?

6.3-Staff-80

Ref: Exh F2-3-1

OPG is requesting approval of Nuclear project OM&A expenditures of $113.9M (2014) and $106.4M (2015). The application notes Project OM&A (Portfolio) is made up of: (1) "Portfolio Projects (Allocated)" which is comprised of AISC-approved budgets for all projects that have an approved business case summary ("BCS"); and (2) "Portfolio Projects (Unallocated)" which do not have an AISC-approved budget, do not have an approved BCS and for which detailed expenditure information cannot be provided. Table 1 in that exhibit indicates the majority of Portfolio Project OM&A costs are "Unallocated" ($107.3M of $148.9M or 72%). In the previous application (EB-2010-0008, F2-3-1, p.2), there was no such concept as "Unallocated" costs identified. It was also not identified in the 2013-2015 Nuclear Business Plan (EB-2013-0321, F2-1-1, Attachment 2) that most costs were "unallocated" (i.e., not AISC approved) as only a lump sum for Portfolio Projects was presented to the OPG Board of Directors for approval.

a) Why does OPG believe it would be appropriate for the Board to approve such a significant amount ($107.3M) related to projects that have not been approved internally by OPG's Asset Investment Screening Committee ("AISC") and for which OPG cannot provide detailed expenditure information or an approved BCS?
b) Board staff is unable to find a description of the composition of the AISC in the application. Are there any members of the OPG Board of Directors on the AISC, as it is not identified as one of the OPG Board Committees in the applicable exhibit (A1-4-1)?
c) Please also explain why the Nuclear Business Plan presented to the OPG Board of Directors for approval did not identify that the majority of OM&A Portfolio Project costs had not received approval by the AISC.

6.3-Staff-81

Ref: Exh F2-4-1, F2-4-2, N1-1-1 (page 15)

The application notes actual and forecast outage OM&A costs over the period 2010 - 2015 primarily reflect items including preparatory work in 2013 and 2014 for the 2015 Darlington Vacuum Building Outage ("VBO") followed by the four unit VBO outage in 2015. OPG also notes outage OM&A expenditures are forecast to increase by $68.0M in 2015 from 2014 plan levels, "primarily" due to the execution of the VBO at Darlington. In addition, outage OM&A expenditures in 2013 were forecast to increase $96.7M from the 2012 actuals and the main driver of that increase was the impact of Darlington's 3-year outage cycle which also included preparatory work for the 2015 Darlington VBO.

The subsequent OPG Impact Statement stated that 39 additional planned outage days would be required for VBO Outage.

a) Please identify the costs associated with the VBO execution in 2015 and the amounts in 2013 and 2014 related to the VBO preparatory work.
b) Please identify the actual 2013 costs incurred for preparatory work for the 2015 VBO.
c) Please also identify the actual costs associated with the most recently completed VBO for both Pickering and Darlington broken down based on VBO preparatory work and VBO execution.

6.3-Staff-82

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

The Auditor General's Report includes a number of findings associated with staff training. With regard to nuclear training, those included a completion rate for the ANO training program of only 56% and completion rates for the CRSS (Control Room Shift Supervisor) training programs in 2012 at Darlington and Pickering of, respectively, 0% and 57%, lower than industry rates of 60-65%.

OPG's response in the Auditor General's Report stated that it is in the process of implementing enhancements to its nuclear training programs. In OPG's Backgrounder that identifies actions OPG is taking to address the findings, there is no mention of any actions related to training.

a) What is the approximate cost associated with training a staff person under each of the following programs: (1) NLO 24-month training program; (2) ANO 36-month training program; and (3) CRSS training program?
b) Please identify the "enhancements" that OPG is implementing to its nuclear training programs,
c) Please provide further discussion on any actions that OPG is taking, or is planning to take, to improve appropriateness, cost effectiveness and success rates of its nuclear training programs.

Issue 6.4

Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the nuclear facilities reasonable?

6.4-Staff-83

Ref: Exh F2-1-1 (Attachment 1), OPG Letter December 5, 2013

OPG's response to the Board's request for information to be provided that disaggregates information related to Pickering A and Pickering B noted that such cost related information could not be provided. The Board's request was not limited to cost related information. Board staff observes that all of the metrics included in the WANO NPI should be available, as page 77 shows the WANO NPI for all 6 units at Pickering A and Pickering B separately. Please provide information that is disaggregated for all of the non-cost-related metrics identified in the benchmarking report where such information is available, particularly those that reflect and impact performance and reliability (e.g., capability factors, backlogs, etc.).

6.4-Staff-84

Ref: Exh F2-1-1 (Attachment 1), N1-1-1

The Nuclear Business Plan sets out "Value for Money" targets for the 2015 test year. The Impact Statement identifies reductions in production and an increase in OM&A costs. Please identify the impact on the "Value for Money" targets of the impact statement.

6.4-Staff-85

Ref: Exh F2-1-1, Attachment 1, page 58

The updated 2012 Nuclear Benchmarking Report indicates the number of 1-Year On-line Corrective Maintenance Backlogs continued to be an issue. Relative to the best quartile at 33, Pickering is almost 5 times higher at 160 and Darlington is over 3.5 times higher at 121. In previous applications, OPG has requested funds to specifically address the backlog issue given their impact on performance. Please provide the number of 1-Year On-line Corrective Maintenance Backlogs for 2012 and 2013.

1-Year On-line Corrective Maintenance Backlog

	Best Quartile	Median	Pickering	Darlington	
2011	33	52	160	121	
	Best Quartile	**Median**	**Pickering A**	**Pickering B**	**Darlington**
2008	4	7	14	28	11

6.4-Staff-86

Ref: Exh F2-1-1, Attachment 1, page 72

Similar to the previous benchmarking report, this updated 2012 Nuclear Benchmarking Report notes that "The minimum expenditure threshold for capitalization at OPG for generating assets is $200k per unit whereas the majority of the companies in the industry have adopted minimum capitalization thresholds that are significantly lower." Why does OPG continue to maintain a capitalization threshold that is significantly higher than the majority of the companies in the nuclear generation industry?

6.4-Staff-87

Ref: Exh F2-1-1, Attachment 1, page 51

With respect to "Observations – Rolling Average Unit Capability Factor (CANDU)", OPG's report states the following:

> **Factors Contributing to Performance**
>
> - Top performing plants achieve low forced loss rates through effective implementation and integration of equipment reliability and human performance programs aligned with industry best practices.

- OPG Nuclear has established a structured cross-functional equipment reliability program based on top industry standards and supported by virtually every department in the organization. The implementation of the program involves focusing the workforce and processes on critical equipment across the fleet.
- OPG is currently working on reducing maintenance backlogs, optimizing the preventive maintenance program and obtaining spare parts for critical equipment.
- Darlington has established a fuel handling reliability project and developed new fuel bundles to prevent unit derating.
- Pickering has established short mid-cycle outages to complete critical maintenance activities to improve the reliability of the plant.

a) With respect to the third bullet on "reducing maintenance backlogs, optimizing the preventative maintenance program and obtaining spare parts for critical equipment":
    i. When did OPG initiate these initiatives, and what is the current status of these programs? Does the statement imply that OPG was not adequately doing these activities previously?
    ii. Please indicate programs documented in the application evidence that are part of these initiatives?
    iii. What is the total cost, and the net cost or savings of these? Where is this shown in the application evidence?
b) With respect to the fourth bullet on Darlington's fuel handling reliability project and development of new fuel bundles to prevent unit derating:
    i. Please provide further description of what this project is and the planned benefits of this.
    ii. What is the cost for this project and what are the expected net costs or savings? Where is this reflected in the application evidence, particularly with respect to the test years' capital and/or operating costs?
    iii. When was this project initiated and what is the current status?
c) With respect to the last bullet, on short mid-cycle outages at Pickering to complete critical maintenance activities:
    i. Please provide further description of this project and how it is intended to improve reliability of Pickering operations?
    ii. Does the statement imply that OPG was not adequately doing these activities previously?
    iii. What is the total cost and net cost (or savings) of this project? Where is this reflected in the application evidence, particularly with respect to the 2014-2015 test years?

6.4-Staff-88

<u>Ref: Exh A4-1-1</u>

As part of the Business Transformation initiative, 1,064.7 Nuclear FTEs were transferred from OPG's Nuclear group to the Corporate group (F2-1-1, Table 3). For example, OPG created a Nuclear Center-Led Engineering Organization and transferred line authority for Design Engineering, Reactor Safety, Performance & Components

Engineering, Fuel Handling, Tritium Removal Facility, Nuclear Waste Management Division Engineering, etc. (A4-1-1, Attachment 1).

Please explain how OPG has taken that transfer of over 1,000 nuclear FTEs into account in the following staffing benchmarking reports:

- National Utility Survey report prepared for OPG by Aon Hewitt, which is intended to assess OPG's relative competitiveness in relation to Target Total Cash Compensation and Pension and Benefits (F5-4-1); and
- Nuclear Staffing Benchmarking Analysis report prepared by Goodnight Consulting (F5-1-1, Part a) and Part b).

6.4-Staff-89

Ref: Exh F4-3-1 (Attachment 6), F2-1-1

There is a significant difference between the OPG Nuclear staffing number that is used for benchmarking purposes and the staffing numbers that are used to support the proposed nuclear revenue requirement for the test years. At page 3 of Exh A4-1-1, OPG states "The transferred resources continue to provide functional support to Nuclear notwithstanding a change in reporting to the corporate centres" in relation to the Business Transformation reorganization. The figure used for benchmarking is 5,587 FTEs for 2013 while the figure supporting the revenue requirement is 8,234 FTEs for 2015 (after 476 FTE reductions since 2013). The latter is comprised of "Nuclear" staff (6,519) and "Allocated Corporate Support to Nuclear" staff (1,714). "Nuclear" staff alone exceeds the FTEs used for benchmarking purposes by about 1,000 FTEs.

a) Please explain the significant difference of about 2,600 FTEs (2015) and 3,000 FTEs (2013) between the FTE figure used for benchmarking purposes and the FTEs used for revenue requirement purposes.
b) Please also provide a table for 2013 showing how the 5,587 FTE benchmarking figure was derived relative to the 8,710 FTEs in 2013 (F4-3-1), with each adjustment used to normalize against comparators (e.g., 35 hour OPG work week vs. 40 hours for comparators, CANDU technology, etc.) as well as all other adjustments including how many nuclear staff were included in that benchmarking figure that were transferred to the Corporate group as part of the Business Transformation reorganization.
c) If Corporate staff that continue to provide support to OPG's nuclear operations was excluded from the benchmarking figure, please explain if Corporate staff in comparator nuclear generators providing similar nuclear-oriented support functions was similarly removed from the comparator staffing numbers. If such an adjustment was made for OPG and not comparators, why is that appropriate given about 20% of staff supporting OPG's nuclear operations (and revenue requirement) are now in the Corporate group? In addition, if it was done for comparators, please explain how that adjustment was made for those that only have nuclear generation, such as Bruce Power.
d) The application (F2-1-1, p.2) also notes that initial results in 2011 indicated OPG Nuclear was 17% above its industry peers and the updated 2013 study shows the gap has narrowed to 8%. To what extent, if any, was that gap reduced due to the

Business Transformation reorganization? What would the gap be if the Business Transformation initiative had not been undertaken?

e) The Goodnight Report notes the following were excluded from the benchmark number: Security, Information Management (provides direct support to Nuclear), Legal and Long Term Leave FTEs. How did Goodnight exclude FTEs from comparators in those functions?
f) The Goodnight Report also notes that “Major Projects/One time initiatives” were excluded and “CANDU-Specific (i.e. unique to CANDU design) Exclusions” were also made. Was the assumption made that none of the other generators in the comparator group have one-time initiatives and there are no FTEs that need to be excluded due to the PWR-Specific technology as the report discusses only FTE exclusions from OPG?

Issue 6.5
Is the forecast of nuclear fuel costs appropriate? Has OPG responded appropriately to the suggestions and recommendations in the Uranium Procurement Program Assessment report?

6.5-Staff-90
Ref: Exh F5-2-1, pages 28-29
The Board’s most recent decision on OPG payment amounts stated “In the next proceeding, the Board will examine OPG’s procurement program to determine whether the company is optimizing its contracting in order to minimize costs to ratepayers. The Board will therefore direct OPG to file an external review as part of its next application.”

OPG retained Longenecker and Associates (“L&A”) to undertake that review. The L&A report notes OPG’s annual uranium requirements are about 2 million pounds/year and OPG’s policy is to maintain a minimum inventory of 1 million pounds or 50% of annual requirements as strategic inventory. However, additional inventory is also held in the form of finished fuel which contains about 2 million pounds. As a result, OPG is carrying about 1.5 years of inventory or 150% of annual requirements. L&A estimates the value of the uranium contained in inventories carried by OPG to be about $170M.

The report also notes no US utility carries finished fuel as inventory and, in comparison, a large US nuclear generator only requires an inventory of between 30% and 35% of annual requirements. It also notes that, in general, nuclear utilities plan for a maximum of one year interruption of deliveries. L&A therefore expressed the view that OPG’s multiple inventories provide a significant potential to “optimize” the existing multiple inventories which would provide an opportunity for reduced investment and therefore lower annual inventory carrying costs which L&A estimated at approximately $12M per year ($170M @ 7% per year).

a) How long has OPG been carrying 150% of annual requirements in inventory and why are they so high relative to other nuclear generators?
b) OPG notes in the application that it accepted this recommendation and the target inventory level has been reduced. How much has OPG reduced inventory levels to

date and what level is OPG now targeting taking into account all three stages of the nuclear fuel supply chain?

c) Where is the reduction in nuclear fuel inventory that is being implemented reflected in the evidence for the 2014-2015 test years?

6.5-Staff-91

Ref: Exh F5-2-1, page 45

The L&A report also notes that OPG's procedures require a review of the Physical and Financial Coverage Limits at least every 2 years and allows for more frequent reviews, but also notes that OPG's risk limits had not been approved by OPG's Enterprise Risk Committee (ERC) since August 2008. L&A therefore recommended that OPG revisit the Physical and Financial Coverage Limits on a more regular basis. Given the uncertainty in the uranium markets, why did OPG not follow its own operating procedures and undertake bi-annual ERC reviews and approvals since 2008?

6.5-Staff-92

Ref: Exh F5-2-1, page 47

The report also notes the quantity held as "strategic inventory" should be based on a risk assessment that is specific to CANDU reactor operational needs and the OPG fuel supply portfolio. However, L&A notes they assume that the one million pound quantity was arrived at based on a "comfortable round number", rather than a quantity which is analytically derived. Was L&A's assumption accurate?

6.5-Staff-93

Ref: Exh F2-5-1, page 13

The application notes OPG expects to reach the new lower target inventory level of 288,000 KgU by the end of 2015. It also notes OPG plans to purchase additional uranium concentrate equal to 40% of OPG's requirements during the test years, with the balance being provided from existing contracts or inventory. The L&A Report that identified inventory levels should be reduced was completed in April, 2012.

a) Please explain why OPG is taking almost 4 years to bring inventory levels to a more optimal level?
b) Please explain why it would not be more appropriate to reduce purchase amounts and thereby reduce inventory levels to an optimal level more quickly in order to lower the carrying costs on fuel inventory, which are ultimately borne by electricity consumers?

6.5-Staff-94

Ref: Exh F2-5-1, page 9

The L&A report noted notes that, since 2008, long term prices have been 35% higher than spot prices. What is OPG's current allocation between long term price contracts and spot market purchases, and what was that allocation when OPG submitted its last cost of service application?

6.5-Staff-95
Ref: Exh F2-5-1, page 49-50
L&A made a number of suggestions in its report in relation to contract terms and conditions including the following: (1) Term contracts should generally be limited to 3-5 years to avoid potentially significant price dislocations; (2) Price ceilings and floors should be included; (3) Price escalation should not be applied to the entire contract price since some of the uranium supplier's costs are fixed; (4) There should be a termination clause as it is prudent to have it in place.

a) Please indicate if OPG's existing fuel contracts are consistent with L&A's suggestions.
b) Is OPG changing, or planning to change, its contracts for nuclear fuel procurement going forward, to be consistent with L&A's suggestions.
c) If OPG has not or does not plan to alter its nuclear fuel contracts in light of L&A's suggestions, please explain why.

Issue 6.6
Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

6.6-Staff-96
Ref: Exh F2-2-3

OM&A costs associated with Pickering Continued Operations are presented in various places in the application. None of those sets of costs are the same and all include the FLCM project. Those differing costs are set out in the table below.

$ millions	**2013**	**2014**
F2-T2-S3 - Attachment 1 (Updated BCS, p.2)	$38.9	$48.8
F2-T2-S3 - Chart 1, p.4	$45.2	$38.9
F2-T2-S3 - Attachment 2, p.5 (Letter provided to OPA)	$38.0	$47.0

In addition, all of the tables in the application, including the information provided to the OPA, identify there will be no future expenditures related to the Pickering B Continued Operations project.
a) Please explain why the costs differ in all three application tables, including a variance of $10M in the 2014 test year. Please identify which set of costs OPG is requesting approval for in this application.
b) Please confirm that OPG will not be seeking approval of any costs related to enabling the continued operations of Pickering in future applications.

6.6-Staff-97
Ref: Exh F2-2-3 (page 1), OPG MD&A - 2013 Third Quarter Report (page 25)
The application notes the net present value ("NPV") associated with Pickering Continued Operations is approximately $520M. The following OPG report

"Management's Discussion and Analysis (MD&A) - 2013 Third Quarter Report" discusses the risks associated with Pickering Continued Operations. It notes that, on August 2013, the CNSC extended the operating license of Pickering to August 31, 2018, subject to OPG meeting several conditions. It also notes that inability to meet those conditions in a timely manner could have an impact on the operating strategy for continued operation of Pickering and states that "[t]he regulatory hold point, if not addressed by the spring of 2014, may require one unit to be shutdown."

Please identify the impact on the NPV of Pickering Continued Operations if that risk were to be realized.

Issue 6.7
Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

6.7-Staff-98
Ref: Exh F2-7-1 page 1-2
The application states OPG is forecasting test period OM&A expenditures of $19.6M for 2014 and $18.2M for 2015 related to the Darlington Refurbishment Project ("DRP"). The $19.6M forecast includes $8.1M for the Operations Trainee program and $5.6M for costs incurred during the Definition Phase. The $18.2M includes $7.7M for the Operations Trainee program and $1.3M for costs incurred during the Definition Phase.

a) Please explain why recovery of $6.9M, i.e. $5.6M in 2014 and $1.3M in 2015, for costs that have already been incurred would be appropriate? Also, given that all costs related to the DRP subsequent to the Board's first Order are subject to a prudence review, please explain what these costs for which OPG is proposing recovery are related to.
b) The application also notes that the Board approved DRP OM&A expenditures of $5.9M for 2011 (EB-2010-0008), while actual costs were only $2.6M, with the $3.3M variance primarily due to lower spending on the Operations Trainee program than OPG had planned. OPG is now requesting approval of a further $15.6M (or 7.8M per year) related to the same training program.
    i. Given that OPG spent less than 50% of the 2011 approved amount and OPG is now requesting over 30% more than the 2011 approved amount on an annual basis, how can the Board be confident the amount requested is actually required for the Operations Trainee program?
    ii. In addition, OPG already has Operations staff at the Darlington plant and it will be refurbished to operate as it has in the past. Please explain the purpose of the "Operations" trainee program, why it is specific to DRP and why such a substantial amount is required in requesting over $20M from 2011 through the test years for this one training program.
    iii. Please also identify all other programs and associated costs related to the training of nuclear staff that are included in the proposed revenue requirement.

6.7-Staff-99

Ref: Exh F2-3-3 Attachment 1 Tab 11 page 8

The protocol agreement between CNSC and OPG 'Additional Protocol For Development Of Probabilistic Leak Before Break Assessments And X-750 Annulus Spacers commits OPG to R&D, inspection and material surveillance activities that extend beyond the scope and timelines of Fuel Channel Life Management Project. What is the contingency plan if R&D, inspection and material surveillance activities extend beyond 2018 and affect DRP base case and the schedule?

Corporate Costs

Issue 6.8

Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.8-Staff-100

Ref: Exh A4-1-1, F4-3-1 (Attachment 6)

The application notes in the Business Transformation exhibit that OPG is targeting a reduction of 2,000 employees from 2011 to 2015 and the footnote indicates about 1,300 are attributed to the regulated operations. However, in the table entitled “FTE, Compensation and Benefit Information for OPG’s Regulated Facilities ("Appendix 2k")”, it indicates a reduction of only 879 from 2011 to 2015. Please clarify the 421 difference in these staffing reductions.

6.8-Staff-101

Ref: Exh F4-3-1, page 10 -12

The application notes the PWU collective agreement was negotiated in early 2012 and it covers the period from April 1, 2012 to March 31, 2015. The wage increases negotiated under the agreement for 2012, 2013 and 2014 are 2.75% for each year.

The application also notes a negotiated agreement with the Society could not be achieved and it was submitted to interest arbitration, with the Interest Arbitrator awarding increases for 2013, 2014 and 2015 of 0.75%, 1.75% and 1.75%, respectively. The Interest Arbitrator also ordered a temporary freeze on pay progression through the established pay grid for Society employees during the test years (2014 and 2015).

a) As noted above, the PWU collective agreement was negotiated in early 2012. OPG had received the Scott Madden benchmarking reports and the Board’s March 10, 2011 decision from the EB-2010-0008 proceeding, as well as results from Aon Hewitt’s fall 2011 National Utility Survey before those negotiations.
    i. Please explain OPG’s strategy in relation to bargaining with the PWU and how OPG took the referenced information and the concerns expressed by the Board in its decision into consideration.
    ii. Was OPG’s bargaining strategy for the PWU similar to the strategy OPG used to negotiate with the Society? If so why the different result (PWU wage

increases are 1% to 2% higher than the Interest Arbitrator awarded to the Society)?

b) The application also notes OPG negotiated a number of cost and productivity offsets to the wage increases in the PWU agreement. Please identify those negotiated cost and productivity offsets.
c) Please identify how much lower the revenue requirement would have been if the wage increases OPG negotiated with the PWU had been equivalent to the wage increases awarded by the Interest Arbitrator to Society staff.
d) Please provide the most recent collective agreements between OPG with each of the Society and the PWU referenced in the application.

6.8-Staff-102

Ref: Exh F4-3-1, Decision of the Court of Appeal for Ontario Docket C55602, C55641, C55633

With respect to the collective agreements that are currently in place, please provide all of the information that OPG relied on when OPG committed to that expense, including all benchmarking materials that were prepared by OPG or relied on by OPG.

6.8-Staff-103

Ref: Exh F4-3-1, page 25

The application refers to a number of cost containment initiatives in relation to benefits. Some of those initiatives were referenced in previous applications including the EB-2007-0905 proceeding (e.g., the outsourcing of benefit administration and the introduction of the Millennium Health & Dental Plan for new external hires). Were any of the cost containment initiatives discussed in the current application implemented since the last cost of service application? If so, please identify these new initiatives.

6.8-Staff-104

Ref: Exh F5-1-1, Part A, page 30

The Nuclear Staffing Benchmarking Report prepared by Goodnight Consulting notes that an adjustment was required because OPG has a 35 hour work week while comparator U.S. utilities have a 40 hour work week. A shorter work week would necessitate more staff to complete the same workload which would result in more staff or more overtime. Has OPG ever attempted to negotiate a change to a 40 hour work week? If not, why not? If yes, why did the PWU and/or Society object?

6.8-Staff-105

Ref: Exh F4-3-1, Attachment 6

The application includes a table entitled “Total Benefits (Current Benefits and Pension & OPEB)” and notes that pension and OPEB cost increases are driven primarily by changes in discount rates and that is a factor beyond OPG’s control. On the other hand, benefits are determined based on Collective Agreement negotiations (i.e., not external factors). Please revise the table referred to above by adding 2 columns to show pension/OPEB and current benefit costs separately.

6.8-Staff-106

Ref: Exh F4-3-1 Attachment 1 (pages 151 and 152 of F4 pdf document – Attachment pages unnumbered), F4-3-1 page 10 Table 2

In his study, Dr. Chaykowski states:

> A comparison between OPG and these major comparators, in the general wage increases negotiated with the PWU over the period 2000 through 2013, indicates that:
>
> - OPG wage increases consistently track at or somewhat lower than the increases observed at these comparators (refer to Figure 6);
> - The cumulative wage increase at OPG, over the 2001-2013 period, is substantially lower than at either Bruce Power or Hydro One (refer to Figure 7); and
> - Pay comparisons by specific occupation (e.g. OPG vs. Bruce Power) shows that earnings at OPG are generally lower.[Footnote reference to EB-2010-0008 Exhibit F4 Tab 3 Schedule 1 Chart 11 (Filed 2010-05-26)] [Emphasis in original]

Table 2 on page 10 of F4-3-1 provides a comparison of 2013 wages for comparable PWU positions at OPG and Bruce Power, which supports the last bullet above.

However, Dr. Chaykowski concludes:

> Therefore,
>
> - **OPG wage settlements are consistently either at or below the wage increases that have been negotiated at the most appropriate comparators in the electricity industry; and the salary levels of individual occupations compare closely as well.** [Emphasis in original]

a) Based on the evidence summarized on the previous page, on what basis did Dr. Chaykowski conclude that “salary levels of individual occupations compare closely as well”?
b) Did OPG provide Dr. Chaykowski with the findings of the National Utility Survey conducted by Aon Hewitt?
   i. If yes, how are the Aon Hewitt results reflected in Dr. Chaykowski’s conclusion.
   ii. If no, why not?

6.8-Staff-107

Ref: Exh F5-4-1 pages 9 and 12

On page 9 of this exhibit, under “Survey Design”, it is stated that the results include “Target Short-term Incentive” and “Target Long-term incentive”. On page 12, it is stated: “Participants were also asked to provide any changes to their short-term incentive plan targets between 2011 and 2013”.

a) Please confirm that the references to “target … incentives” and to “changes to … incentive plan targets” only relate to the incentive compensation if the expected/intended performance as designed into the plan is achieved, and not based on actual payout based on the actual performance of the firm or unit for the survey period.
b) Similarly, please confirm that “changes to the short-term incentive plan targets” would reflect changes in the incentive plan designs (e.g. % or amount of salary/bonus at risk) and not to changes in performance between 2011 and 2013.
c) In each comparator Group, how many, or what percentage of firms, have short-term or long-term incentive plans?
d) Does OPG have short-term or long-term incentive plans in its employee compensation? If so, for which groups of employees (PWU, Society and/or Management)?

6.8-Staff-108

Ref: Exh F5-4-1, Decision EB-2010-0008 page 85

In the Board’s previous payment amounts decision (p.85), the Board directed OPG to conduct an independent compensation study to be filed with the next application. The Board found that the compensation benchmark should be set at the 50th percentile as it is consistent with the Agency Review Panel recommendations.

OPG, in response, retained Aon Hewitt and they prepared the National Utility Survey report with comparisons for PWU, Society and Management staff based on three industry groups; Group 2 is a subset of Group 1. The results of that report are presented on numerous pages in the form of a slide deck. Board staff has summarized those results associated with the 50th percentile in the table below for “Total Cash Compensation”. Aon Hewitt notes, if it’s within +/- 10%, it is "at market" or competitive to the external market. It has now been almost 15 years since the break-up of Ontario Hydro. Please explain why it is necessary to pay PWU staff 20% more than comparator utilities (based on the first two groups that focus on the electricity sector) while Society staff are paid at market.

Group 1: Power Generation, Electric Utilities, and Nuclear, Research, Development and Engineering (NRDE)	
PWU	+20.5%
Society	–2.9%
Management	+3.0%
Group 2: Nuclear Power Generation and Electric Utilities	
PWU	+19.1%
Society	–3.8%
Management	–3.4%
Group 3: General Industry	
PWU	+29.4%
Society	+23.3%
Management	+20.9%

6.8-Staff-109

Ref: Exh F5-4-1, 2013 Annual Report of the Office of the Auditor General of Ontario (Dec. 10, 2013)

The Auditor General's report at page 163-164 notes that OPG payroll data indicate that a large number of employees receive salaries that exceed the maximum set out in the base salary schedule. Was Aon Hewitt's analysis based on salary schedules or actual salaries?

6.8-Staff-110

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

Since the last benchmarking report in 2011, OPG continues to have a number of positions that are overstaffed relative to the benchmark. As noted in the Auditor General's report at pages 160-161, this occurs mainly in support functions (e.g., general maintenance, administrative support and human resources). OPG's response discusses the Business Transformation initiative.

a) Please explain why OPG has made essentially no improvements in 2 years in those areas such as the case highlighted by the Auditor General, where Facilities staff has only gone from 173% above in 2011 to 170% above the target staffing level by 2013.
b) Please explain why such positions require a multi-year initiative to at least begin to address the overstaffing issue.

6.8-Staff-111

Ref: Exh F4-3-1 pages 29-30

OPG states:

> The long-term inflation assumption used for projecting pension and OPEB costs continues to be based on the Ontario consumer price index. OPG uses the final year in the most recent forecast from a publicly available economic report, subject to an adjustment if the rate is outside of the Bank of Canada's target range for inflation. The salary schedule escalation rate assumption used to project the 2013-2015 pension and OPEB costs is equal to the long term inflation assumption plus 0.5 per cent. As in the past, OPG's independent actuary has reviewed and agreed with these assumptions.

Chart 1 on page 30 shows a 2.0% inflation estimate for all years, from 2010 actual to 2015 test year.

a) What is the "publicly available economic report" for the forecast of the Ontario CPI used for the long-term inflation assumption for projecting pension and OPEB costs that OPG uses? Does OPG look at other available forecasts to corroborate this?
b) What is the forecasted Ontario CPI used for estimating the pension and OPEB costs reflected in the 2014-2015 revenue requirement in this application? When was this forecast published and what was the forecast period?

c) Chart 1 shows a superscript "[4]" for 2014 and 2015, but there is no associated reference (e.g. footnote). If missing, please provide the footnote or reference.

6.8-Staff-112
Ref: Exh N1-1-1 pages 4-11
Please provide an update to the pension and OPEB cost evidence in the Impact Statement filed on December 6, 2013 as follows:
a) Please provide revised evidence using the AA bond yields as at December 31, 2013 rather than at June 30, 2013.
b) Please use the actual returns of the pension plan's assets as at December 31, 2013 to forecast 2014 and 2015 pension costs rather than the results as at June 30, 2013 with a projected return at 6.25% for the remaining six months of 2013.

6.8-Staff-113
Ref: Exh A2-1-1 Attachment 1 page 117
a) Please provide the tables similar to note 10 in OPG Inc.'s audited financial statements that will show the funded status as at December 31, 2013 using the updated evidence requested above for discount rate and actual returns both as of December 31, 2013.
b) Please provide a similar updated table for the regulated business as at December 31, 2013 and describe how the allocations from OPG Inc. to the regulated business were prepared.

6.8-Staff-114
Ref: Exh N1-1-1 Attachment 1, report page 6
OPG's latest actuarial valuation as of January 1, 2011 for funding purposes of the RPP is the basis of contributions for 2013. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014. In order to project contributions to the RPP for 2014 and 2015, an estimate of the going concern and solvency positions of the RPP is required.

a) Has OPG made any special solvency payments above the minimum required contribution since 2007?
b) Has OPG made any other payments other than solvency contributions since 2007 such as going concern special payments?
c) Please provide a table for the period 2007 to 2013, plus projections for 2014 and 2015, that shows 1) the annual accounting pension benefit costs before capitalization in fixed assets; 2) contributions to the pension plan other than solvency payments; and 3) any special solvency contributions shown separately.

6.8-Staff-115
Ref: Exh F4-3-1
Regarding capitalization of payroll and benefit costs:

a) What percent of pension and OPEB costs was capitalized in 2013 to capital assets?

b) What percent of pension and OPEB costs is capitalized in the 2014-2015 test period to capital assets?

6.8-Staff-116

Ref: Exh F4-3-1 page 31, Mercer Press Release January 2014

In the pre-filed evidence OPG disclosed that the return on the plan assets was 1.7% at the end of August 2013. As noted in the Mercer Press Release, other pension plans in Canada have reported much higher returns than OPG for the entire year 2013.

a) What was the return on plan assets for the entire year ended December 31, 2013?
b) If OPG's return on plan assets was lower than other plans (as identified in the Mercer press release) have reported for 2013, please explain why OPG's returns lagged behind the other pension plans. Please refer to analysis published by Mercer and other experts where possible.
c) What steps has OPG taken to improve the returns on the plan assets in the test period 2014-2015?

6.8-Staff-117

Ref: Exh A1-4-1, Financial Post - July 2013

The OPG Board has established the Audit and Finance Committee, which among other responsibilities, provides oversight of the performance of the OPG Pension Fund.

a) Does this committee, or OPG management, set objectives for the plan's performance? If yes, please file the objectives for 2013 and 2014.
b) Please explain what actions have been made recently to deal with the deficit in the fund. Please refer to the article in the Financial Post.

6.8-Staff-118

Ref: Exh N1-1-1-Pages 4-9

Prior to the comprehensive accounting valuation, OPG's mortality assumptions were based on the industry standard actuarial 1994 Uninsured Pensioner ("UP94") mortality table, as adjusted by a factor of 85%, and the standard future mortality improvement Scale AA. This 85% factor reflected improvements in longevity of Canadians in general.

Do OPG's employees have a longer life expectancy than the Canadian population on average? Please explain with reference to the specific data related to OPG's employees and retirees.

6.8-Staff-119

Ref: Exh N1-1-1-Pages 4-9

Using the following assumptions, and adding others if required for the example, please show the pension benefit obligation under the 85% of UP94 methodology and under the new proposed methodology which uses the recently updated mortality tables.

- Male employee 45 years of age.
- Salary $100,000.
- Female spouse who does not work for OPG, who is 40 years of age.

- No children or other beneficiaries.

6.8-Staff-120

Ref: Exh F5-4-1 Pages 31-36

As shown in the benchmarking study, OPG's average pension value delivered is 16.10% of pay compared to 10.77% for the comparator group.

Does OPG plan to make changes to its compensation program to lower the pension and benefit costs to be closer to those of the comparator group?

6.8-Staff-121

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

At page 166 of the Auditor General's report, it states the following: "Since 2005, the employer-employee contribution ratio at OPG has been around 4:1 to 5:1, significantly higher than the 1:1 ratio at Ontario Public Service."

a) Is OPG considering changing the contribution ratio to 1:1?
b) If not, please explain why the current contribution ratio is reasonable. What research had OPG done when it committed to the 4:1 to 5:1 employer-employee contribution ratio? Can OPG point to any comparable organizations that have a similar employer-employee contribution ratio?
c) If the employer-employee contribution ratio were reduced to 1:1 for the test years, what impact would that have on the revenue requirement?

6.8-Staff-122

Ref: Exh N1-1-1-pages 4-10

a) Please confirm that OPG uses the accounting valuation methodology to determine post-employment benefits other than pension costs (known as PBOPs or OPEBs) and supplementary pension plan ("SPP") for the test period.
b) As noted in Exh N1-1-1 chart 2, please confirm that OPG currently recovers more money from ratepayers than it pays to retirees because the accounting costs included in payment amounts are higher than amounts actually paid to retirees.
c) As noted in Exh N1-1-1 chart 4, please confirm that OPG will continue to recover more from ratepayers than it pays to retirees during the test period.

6.8-Staff-123

Ref: Exh F4-3-1, FERC Policy: 61FERC61 330 PL63-1-000

a) Does OPG have a separate fund, or irrevocable trust (as noted in FERC policy 61FERC61,330), into which OPEB and SPP recoveries that exceed payments to retirees are deposited and managed to earn a return on behalf of ratepayers?
b) Please provide the legal rationale and/or explanation that support OPG's statement from page 129 of its reply argument in EB-2010-0008.

    "In addition, OPG submits that it is doubtful whether the OEB has the jurisdiction to mandate OPG to set cash payments aside in a segregated fund for a specific use. Board staff's argument is silent on this question as well as on how such a fund would be structured, managed and paid for."

c) Has OPG undertaken a review of what would be required to set up and manage such a segregated fund or irrevocable trust similar to that in the FERC guidelines as provided?
d) If OPG has not undertaken this review, please explain why OPG believes that the Board should allow OPG to continue to use ratepayer money, recovered for OPEBs decades in advance of the cash requirement, for general corporate purposes.
e) Please provide OPG's estimate of the costs that would be incurred to create an irrevocable trust for OPEBs and SPP and what the annual operating costs would be following the FERC guidelines as provided.

6.8-Staff-124
Ref: ExhN1-1-1-pages 4-11
Please provide a table that shows separately the OPEB and SPP accounting amounts before capitalization to capital projects, the amounts actually recovered from ratepayers, the amounts paid to retirees and the net excess amount of recoveries from 2007 through 2013. Please project these values for the test period 2014-2015.

Issue 6.9
Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

6.9-Staff-125
Ref: Exh F3-1-1 page 4
The evidence states that "Support Services costs decrease over the 2013-2015 periods mainly due to Support Service groups leveraging attrition by not replacing staff that retire, implementing organizational changes to take advantage of economies of scale by consolidating staff that perform similar work, streamlining processes, and eliminating lower value work."

a) Please list all the "lower value work" that will be eliminated as part of Business Transformation in 2013-2015.
b) What savings (in dollars) will be achieved through the elimination of lower value work in 2013-2015? Please provide data by year.

6.9-Staff-126
Ref: Exh F3-1-1
Exhibit F3 describes the corporate support services.

a) Please confirm the data in the following table for corporate support services.

	$millions	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test	2015 Test
1	OPG	362.0	364.7	547.7	597.9	577.6	547.8
2	Nuclear	226.5	233.1	408.4	451.0	433.9	417.4
3	Hydroelectric - Pres	22.4	22.0	24.5	29.7	29.8	26.9
4	Hydroelectric - N.Pres	31.4	32.3	36.6	38.8	42.1	39.6

5	Total Regulated (2+3+4)	280.3	287.4	469.5	519.5	505.8	483.9
6	Total Unregulated (1-5)	81.7	77.3	78.2	78.4	71.8	63.9
7	%Current Regulated (2+3)/1	69%	70%	79%	80%	80%	81%
8	%Current & Newly Prescribed 5/1	77%	79%	86%	87%	88%	88%

b) Please explain the trend in corporate support service expense for total regulated (row 5) for the period 2010 to 2015.
c) The unregulated business corporate support service expense is largely unchanged in the period 2010 to 2013 (row 6). Please explain why the costs for the regulated business (nuclear and hydroelectric) are going up when the costs for the unregulated business are largely unchanged.

6.9-Staff-127
Ref: Exh F3-1-1
Exhibit F3 describes the corporate support services.

a) Please complete the following table for corporate support services. Provide references for the data from the pre-filed evidence and EB-2010-0008.

		2010 Plan[1]	2010 Actual	2011 Board Approved	2011 Actual	2012 Board Approved[2]	2012 Actual
1	Nuclear						
2	Currently Regulated Hydroelectric						
3	Variance						

Note 1 – As noted in EB-2010-0008
Note 2 – As restated for Business Transformation

b) Please provide explanations for the variances, and the trend if any, determined in row 3.

6.9-Staff-128
Ref: Exh F3-1-1, Tables 1, 6 and 7
Table 1 summarizes the actual and forecast corporate support costs for OPG, regulated and unregulated, for the period 2010 to 2015. The most significant increases in total dollars and % change are related to three functions: Business and Administrative Service, People and Culture and Corporate Centre.

a) Tables 6 and 7 summarize the Business and Administrative Service costs for the regulated hydroelectric and nuclear businesses respectively. As summarized in Table 7, the Real Estate costs for the nuclear business in 2011 were $31.7M, and increased to $96.2M in 2012. At Exh F3-1-1 page 8, it states that the Real Estate group consists of three departments: Real Estate Services, Facilities and Projects and Business Services.

i. Please provide actual and forecast costs for each of the three Real Estate departments for the period 2010 to 2015.
ii. Why did Real Estate costs of nuclear more than triple in 1 year?
iii. At page 9 of Exh F3-1-1, it states that the Business Services department of the Real Estate function provides “administrative support for staff located at 700 University Avenue, Pickering, and Darlington, as well as other nuclear groups located at certain facilities in Durham Region.” Is the scope of this administrative support different than the scope included in the EB-2010-0008 proceeding? If yes, is the change part of Business Transformation? If the change is part of Business Transformation, please explain how moving to a centre-led organizational model for administrative support “allows best practices to be better shared and integrated across the company.”, as noted in Exh A4-1-1 page 2.

b) Corporate Centre costs, as summarized in Table 1, increased from $22.3M in 2011 to $43.6M in 2012. Please provide actual and forecast costs for sub-functions of Corporate Centre and an explanation for the increased costs.

6.9-Staff-129

<u>Ref: Exh F3-1-1</u>

Commercial Operations and Environment includes the Electricity Sales & Trading function. At page 16 it states, the “Electricity Sales & Trading group co-ordinates the offering of OPG’s generation into the IESO market to maximize OPG’s net revenues by integrating and optimizing the generation portfolio and trading activities.” How will the function of Electricity Sales & Trading change when the amount paid to OPG for generation from the newly prescribed hydroelectric facilities is no longer based on HOEP? How are the changes, if any, reflected in the cost allocation between regulated and unregulated businesses?

6.9-Staff-130

<u>Ref: Exh F3-1-1</u>

The application at pages 6 to 8 summarizes IT benchmarking results for OPG with respect to the Electricity Utility Cost Group Comparator Group data, for the year 2011.

The 2011 results indicate that OPG’s IT costs were within the second quartile for IT spending per employee and within the third quartile for IT spending per GWh. While the actual costs are lower, OPG’s performance with respect to the quartiles is unchanged from 2008 data reported in the EB-2010-0008 proceeding.

How much lower would the 2014-2015 revenue requirement be if IT costs were within the top quartile for IT spending per employee and IT spending per GWh?

6.9-Staff-131

Ref: Exh F3-1-1

The application at pages 14 to 15 summarizes People & Culture benchmarking results for OPG with respect to the Electricity Utility HR Metrics for the year 2012.

The 2012 results indicate that OPG's HR Expense Factor (total HR expense divided by the number of regular HR employees) was $172k/HR employee. This result is between the median of $155k and bottom quartile of $175k for OPG's peer group of very large utilities. The 2008 data reported in the EB-2010-0008 proceeding was $120k.

OPG's HR Employee Ratio improved modestly from 64 in 2009 to 65 in 2012, but the result remains in the bottom quartile.

How much lower would the 2014-2015 revenue requirement be if People & Culture costs were within the top quartile for HR Expense Factor and HR Employee Ratio?

6.9-Staff-132

Ref: Exh F3-1-1

OPG filed a Finance Benchmarking report prepared by the Hackett Group in the EB-2010-0008 proceeding. Finance metrics were not provided in the current application.

a) What is "Finance Cost as a Percent of Revenue after Rebates" for the most recent year for which OPG has actual data?
b) What are Finance "FTEs per OPG's Revenue after Rebates" for the most recent year for which OPG has actual data?

6.9-Staff-133

Ref: Exh F3-1-3

Exhibit F3-1-3, as filed on December 5, 2013, summarizes the Regulatory Affairs Department costs. Table 1 provides costs for the period 2010-2015.

The external legal costs are listed separately from the Regulatory Affairs Division costs. Are the external legal costs covered under the Corporate Affairs budget?

6.9-Staff-134

Ref: Exh F3-1-3

Exhibit F3-1-3 summarizes the Regulatory Affairs Department costs.

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

	Historical Year(s)	2013 Bridge Year	2014 Test Year
Expert Witness costs			
Legal costs			
Consultants' costs			
Incremental operating expenses associated with staff resources allocated to this application.			
Incremental operating expenses associated with other resources allocated to this application. Please identify resources involved.			
Intervenor costs			
TOTAL	$ -	$ -	$ -

6.9-Staff-135

<u>Ref: Exh F3-3-1 and Exh F3-3-2, Decision of the Court of Appeal for Ontario Docket C55602, C55641, C55633</u>

These exhibits provide an overview of OPG's procurement process and provide a listing of purchased services – support services OM&A contracts. Chart 1 at Exh F3-3-2 lists 3 vendors, New Horizons System Solutions ("NHSS"), ARI Financial Services Inc. and Microsoft.

a) The chart at Exh F3-3-2 states that the NHSS procurement process was single source and notes "leveraged renegotiation after October 1, 2009". Please explain the "leverage renegotiation" and the rationale for this procurement process and how it is consistent with OPG's procurement process.
b) For every other OM&A expense, indicate whether the procurement process followed was consistent with OPG's procurement process. If not, please explain why.
c) Please identify every expense that was committed to prior to the test period. Please also provide all of the information that OPG relied on when OPG committed to each of those expenses including the cost that has been committed for each of those expenses in the test years and the associated total cost for each expense. Please provide that information broken down by year, including before and after the test period, where applicable.

6.9-Staff-136

<u>Ref: Exh F5-5-1</u>

OPG's cost allocation methodology for corporate support services and centrally held costs was reviewed by HSG Group Inc. The report filed by HSG states that a source document for its report was "OPG Revenue and Cost Assignment and Allocation Methodology" draft provided by OPG as of April 18, 2013. Does HSG's analysis and conclusions differ in any significant way from the OPG document?

6.9-Staff-137

<u>Ref: Exh F5-5-1</u>

At page 7 of the HSG report, it states:

> Starting in 2012, OPG implemented a Business Transformation, in which employees who had reported to generation Business Segments were transferred to CSA departments. As a result, the total dollars in the CSA department budgets, and in OPG's cost allocation, increased. However these costs have been directly assigned to the Business Segments that are supported, and the transfer of employees as part of OPG's Business Transformation did not cause any costs shifts between Business Segments. **The increase in costs allocated to a Business Segment in the allocation process was offset by an equal decrease in directly incurred costs.** The Business Transformation is discussed further in Section V Part A. A summary of the effect of the Business Transformation on the 2013 Budget for Service Recipients and Service Providers is presented in Exhibit C. [emphasis added]

Please explain how the data in Exhibit C demonstrate that the increase in costs allocated was offset by an equal decrease in directly incurred costs. In particular:

a) Please confirm that the data are $thousands and not $millions
b) There is a transfer of $2,048k from Hydro/Thermal Corporate Relations & Communications noted in the bottom table. However there is a transfer in of $20,239k in the upper table.
c) There is a transfer of $12,122k from Hydro/Thermal Corporate Business Development & Risk noted in the bottom table. However there is a transfer in of $16,428k in the upper table.

Issue 6.10
Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

6.10-Staff-138
<u>Ref: Exh F4-4-1 Table 1</u>
Relative to 2013, the proposed increase in Nuclear Insurance is 33% and 39% in the test years. Similar to OPG's previous application (EB-2010-0008), the proposed cost increase is based on an assumption that new legislation will be passed in the test years. The web page referenced in the application notes that the Federal Government "expects" to table proposed legislation. It is Board staff's understanding that this is about the fifth time the Federal Government has expected to pass such legislation.

a) Why is OPG certain that new legislation will receive Royal Assent this time?
b) Based on the 33% increase in 2014, it appears OPG has assumed legislation will receive Royal Assent in 2014. What specific date has OPG assumed for the purpose of this application?
c) In the Board's EB-2010-0008 Decision, the Board denied OPG's proposed cost increase in stating *"It is premature to increase nuclear insurance costs because of a bill that is still being debated by the federal government."*[2] In that proceeding, the

[2] Decision with Reasons (EB-2010-0008), page 96. .

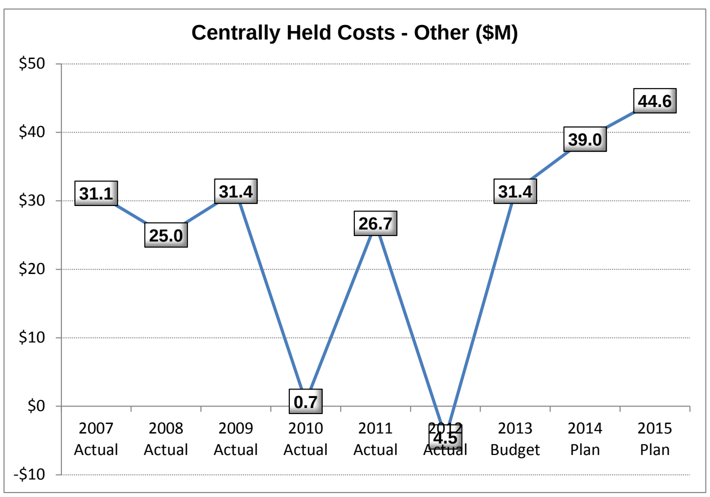
proposed bill had passed first reading before it failed to receive Royal Assent. In this instance, a bill has not even been proposed. Given the circumstances, why does OPG believe the Board should deviate from its finding in the previous case?

6.10-Staff-139

Ref: Exh F4-4-1 Table 1

The chart below is related to the “Other” category of Centrally Held Costs. The chart includes actual costs from the previous application (2007 – 2009) as well as the actual and proposed costs from the current application. There is a consistent trend of alternating increases and decreases each year. The actual costs also consistently peak at just over $31 million until the bridge year. However, in the test years, there is a deviation from both of those trends. First, instead of alternating increases and decreases, it increases in both of the test years following an increase in 2013 (i.e., 3 straight years of increases). Second, the proposed increase is substantially higher – about $13 million – than the amount it has consistently peaked at.

a) Please explain the deviation from the two trends noted above.
b) Please also provide a table that provides a breakdown of all the different types of costs and associated amounts that are included in the “Other” category for each of the years in the current application (2010-2015).



6.10-Staff-140

Ref: Exh F4-4-1 (Table 2 and Table 3), F4-3-1(Attachment 6)

Table 2 and Table 3 provide a breakdown of the Centrally Held Costs for the Previously and Newly Regulated Hydroelectric groups. From 2010 to 2015, the percentage increase in the allocation of those costs is about 5-fold higher for the Newly Regulated Hydroelectric group at **156.3%** compared to **32.7%** for Previously Regulated Hydroelectric. The application notes that Pension and OPEB-related costs comprise the majority of the Centrally Held Costs and the primary driver of the increase in those costs is the discount rate which would have the same impact on both groups. The other driver that impacts Pension and OPEB costs is the number of FTEs and the table in F4-

3-1 shows a declining trend for both groups. Another component of Centrally Held Costs where there is a notable divergence in the trend between the two hydroelectric groups is "Other" costs – from 2010 to 2015, Previously Regulated increases by $1 million while Newly Regulated increases by $7.2 million, with all of the increase in the latter occurring in the bridge and test years. Please explain why the increase in the allocation of these two components of Centrally Held Costs is significantly higher for the Newly Regulated group.

Depreciation

Issue 6.11
Is the proposed test period depreciation expense appropriate?

6.11-Staff-141
Ref: Exh F4-1-1 page 4
Please provide a detailed overview of OPG's asset retirement accounting policies and procedures (including treatment of gross asset, accumulated depreciation, salvage, cost of removal and determination of gains and losses).

6.11-Staff-142
Ref: Exh. F4-1-1 and Ref: Exh. F5-3-1
Please provide all reports, memorandums and recommendations of the Depreciation Review Committee ("DRC") for the regulated business in 2013 and 2014 including documents or meeting minutes of OPG's Approvals Committee approving the recommendations of the DRC.

6.11-Staff-143
Ref: Exh. F5-3-1
OPG publications and several announcements by OPG's senior officials have indicated that the new tunnel at Niagara Falls will provide electricity service for at least 100 years. On March 21, 2013 OPG issued a News release entitled, **"Water Now Flowing Through Newly Completed Niagara Tunnel Project will generate 100 plus years of renewable electricity."** Please see below two web links on the subject of the tunnel's service life. Consequently, does OPG agree that the new tunnel should have a useful life of more than 100 years? If no, please explain.
http://www.opg.com/generating-power/hydro/projects/niagara-tunnel-project/Documents/Niagara%20Tunnel%20media%20release%2021%20March%202013.pdf
http://www.renewableenergyworld.com/rea/news/article/2013/04/niagara-tunnel-completion-important-piece-for-ontarios-hydroelectric-power-supply

6.11-Staff-144
Ref: Exh. N1-1-1 Chart 1 and Exh. F4-1-1
Chart 1 shows a change to depreciation and amortization of $9M for the test period due to changes arising from OPG's 2014 - 2016 Business Plan.

a) Please explain the reasons for the increase in depreciation expense.
b) Please confirm that OPG is not seeking recovery of this incremental amount and thus there is no need to update applicable tables and amounts for depreciation and amortization including tables 1 and 2 (at Exh. F4-1-1) in the application.

Issue 6.12
Are the depreciation studies and associated proposed changes to depreciation expense appropriate?

6.12-Staff-145
Ref: Exh. F5-3-1 Background
Gannett Fleming states, "OPG continues to depreciate its regulated assets using a straight line method of depreciation, with the depreciation rates being calculated based on the Average Life Group – Whole Life Procedure."
a) Please define Average Life Group - Whole Life Procedure by its separate components.
b) Please explain how the Average Life Group – Whole Life Procedure is applied to determine asset service lives and depreciation.
c) Please indicate whether the Average Life Group procedure is applied to the average life on a broad group, vintage year group, equal life group or other group basis to the asset classes. If varying procedures apply, please provide the asset classes to which these procedures are applied and explain the rationale for their use.
d) Is the Average Life Group – Whole Life Procedure applied to nuclear or hydroelectric generating stations? If not, please identify the applicable procedure.
e) Please identify other depreciation procedures used by other regulated power utilities and please explain why they were not recommended for use in the case of OPG.

6.12-Staff-146
Ref: Exh. F5-3-1 Background
Gannett Fleming states, "The Average Life Group – Whole Life procedure has been used by OPG for a number of years and **has previously been approved by the OEB**." [Emphasis added]
a) Please provide the references to previous proceedings where OPG discussed the specific issue of "Average Life Group – Whole Life procedure" as the basis upon which OPG uses to determine its depreciation and sought the Board approval of this depreciation procedure.
b) Please provide the references in previous proceedings where the Board has explicitly approved the "Average Life Group – Whole Life procedure" for OPG.

6.12-Staff-147
Ref: Exh. F5-3-1 Depreciation Policy Ref: Exh. F4-1-1 Attachment 1 and Ref: Exh. F5-3-1
Gannett Fleming states, "The use of the Average Life Group - Whole Life Procedure **applies the same annual accrual rate to all vintages of plant**, which is calculated by dividing 100% by the average service life estimate. As such, a common life estimate is

applied to each of the asset vintages, and each of the assets within each vintage. This procedure is widely used by a number of regulated electric utilities throughout North America, and results in a reasonable recovery of capital investment." (Emphasis added)

Another procedure used is the Equal Life Group, which essentially segregates assets into groups of assets with the same life expectancy and plant-life statistics is derived from the group's estimated survivor curve.

a) Please describe the difference between the equal life group procedure and the average service life procedure.
b) Does Gannet Fleming believe that the average service life procedure provides a better matching of depreciation than the equal life method? Please explain.
c) Has Gannet Fleming recommended the equal life method in other depreciation studies it has conducted for other regulated utilities, and if so, please provide the reasons for this recommendation.
d) Did Gannett Fleming quantify annual depreciation under the equal life group procedure and the average service life procedure, and if so, what is the difference?
e) For depreciation purposes, please indicate whether regulated electric utilities in North America use the single unit (as opposed to the group) method for materially large readily identifiable assets, such as, nuclear stations or hydroelectric dams, and if so, to what extent is it used?

6.12-Staff-148

<u>Ref: Exh. F5-3-1 Depreciation Policy Ref: Exh. F4-1-1 Attachment 1 and Ref: Exh. F5-3-1</u>

In theory, with respect to the vintage group and equal life group, there will be no asset retirement dispersion, if all assets are retired at exactly the same average service life. However, this is not reality.

The retirement dispersion of assets is generally as follows:

- Half will retire before the average service life
- A portion will retire at the around the average service life
- The reminder will retire longer

a) Did Gannett Fleming use empirical data including Iowa curves (or other curves) to determine the need for any changes to the service lives of OPG fixed assets?
b) Please provide a detailed summary of the empirical data, Iowa curves (or other curves), the best fit service-life, and analysis used in the two depreciation studies.

6.12-Staff-149

<u>Ref: Exh. F4-1-1 Attachment I and Exh. F5-3-1</u>

In its EB-2010-0008 Decision with Reasons, the Board directed OPG to file an independent depreciation study at the next [payment order] proceeding. The Board also stated that such a study provides assurance to the Board and all parties that the depreciation and amortization expenses, which are significant, are reasonable. In this proceeding, OPG has filed two depreciation studies, covering the prescribed assets for the periods as at December 31, 2010 ("2011 depreciation study") and as at December 31, 2012 ("2012 depreciation study").

a) Please provide a summary of changes made to the asset service lives resulting in charges to depreciation and amortization expenses for ratemaking purposes since the last payment order proceeding EB-2010-0008.
b) Please explain why OPG made changes to asset service lives resulting in charges to depreciation and amortization expenses given that OPG was specifically directed by the Board to file an independent depreciation study in its next proceeding which would be subject to the Board's review and approval before any proposed changes are permitted for ratemaking purposes?
c) Please clarify whether the impact of the changes made to the end of life for Bruce A and B stations resulting in a net decrease in depreciation expense of approximately $35M in 2013, exclusive of the impacts of the December 31, 2012 ARC adjustment, were recorded in the Bruce Lease Variance Account. (Exh F4-1-1 page 8)

6.12-Staff-150

Ref: Exh. F4-1-1 Attachment I, page I-6

Gannett Fleming also notes that through the process of implementing "Internal Financial Reporting Standards ("IFRS"), OPG reviewed its listing of accounts in order to comply with the componentization requirements of the International Accounting Standard No. 16. (IAS 16) OPG determined that no changes to the accounts were required.

a) Please provide the documentary evidence including reports and analysis showing that OPG determined that no changes to the accounts were required for the componentization requirements under IAS 16.
b) Please provide the documentary evidence showing that OPG's Approvals Committee, senior management or external auditors reviewed and concurred with this conclusion that OPG's componentization was in compliance with IAS 16.

6.12-Staff-151

Ref: Exh F5-3-1 Review of Accounting Policies

2012 Depreciation Study states: "Gannett Fleming also notes that any amount of cost of removal (that is not associated with the retirement of an asset for which an Asset Retirement Obligation ["ARO"] is established) is charged directly to the income statement in the year of the transaction. Both the recording of gains and losses to income and the charging of cost of removal to income is in accordance with the provisions of US GAAP. As previously noted in the 2011 Depreciation Study (page II-7), while these are not the traditional practices of regulated utilities, Gannett Fleming believes that the nature of the large plant components and small amount of retirement transactions make this policy viable and reasonable for OPG."

a) For assets grouped (excluding assets with AROs) for purposes of the depreciation provision, please identify and indicate the traditional practices of regulated utilities in Canada and the United States of America for any amount of cost of removal.
b) Please provide the reasons for OPG's departure from the traditional practices of regulated utilities.

c) Did OPG adopt this accounting change in 2011 due to its intent at the time to adopt IFRS?
d) Why did OPG not seek prior authorization of the Board for this accounting change for ratemaking purposes?
e) How are gains and losses treated for ratemaking purposes and what amounts are included in the test period by year?
f) What is the cost of removal treatment for Asset Retirement Obligations?
g) Is the change in accounting policy applicable to group assets, higher valued units or both?

6.12-Staff-152

Ref: Exh. F4-1-1 and Ref: Exh. F5-3-1

Please confirm whether or not OPG's Approvals Committee or senior management has accepted and adopted all the recommendations of Gannet Fleming in its two depreciation studies for 2011 and 2012 including the specific recommendation that OPG should conduct an independent depreciation study every five years.

6.12-Staff-153

Ref: Exh. F4-1-1 Attachment 1 page I-6

As described in the Results section of this report, Gannett Fleming recommends changes to the average service life estimates for three accounts as follows:

- Account 10400 – Hydroelectric – Turbines and Governors – from the currently approved 75 years to 70 years;
- Account 10210 – Hydroelectric – Service and Equipment Buildings – from the currently approved 50 years to 55 years;
- New Account – Hydroelectric – Security Systems – Create a new plant account with an average service life estimate of 10 years.

a) For the above-noted accounts, please provide the NBV (including gross plant and accumulated depreciation), the previous average service life estimate, the previous annual depreciation expense, the new annual depreciation expense and the net change.
b) Did Gannett Fleming use empirical data including Iowa curves to determine the need for these changes? If so, please provide the information. If not, please explain.

6.12-Staff-154

Ref: Exh. F5-3-1 Depreciation Policy

Gannett Fleming states, "Depreciation related to the nuclear asset classes continues to be based on the lesser of the generation station life or asset class life.

a) Please clarify the difference between generation station life and asset class life.
b) Please explain how this depreciation method of lesser of the generation station life or asset class life is applied in relation to OPG's nuclear stations.

6.12-Staff-155

Ref: Exh. F5-3-1 Depreciation Policy

Gannett Fleming states, "Given that the major operating components at the Darlington plant are expected to be refurbished in the near future, Gannett Fleming finds that the December 31, 2051 date continues to be reasonable, as recommended in the 2012 DRC review. Please provide the reference to this recommendation in the 2012 DRC review.

6.12-Staff-156

Ref: Exh. F5-3-1 Attachment I Part I

Gannett Fleming recommended six changes to the average service life estimates, as follows:

- Account 10318000 – Hydroelectric – Gates, Stoplogs and Operating Mechanisms – Change average service life estimate from the currently approved 50 years to 55 years;
- New Account – Hydroelectric – Roofing – Create a new plant account with an average service life estimate of 30 years;
- New Account – Hydroelectric – Fencing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Roofing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Large Circulating Water Motors (greater than 200Hp) – Create a new plant account with an average service life estimate of 30 years; and
- Reclassification of assets for nuclear turbine generator controls from existing Account 15411100 – Turbines and Auxiliaries with a 55-year average service life to existing Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

a) For the above-noted accounts, please provide the NBV (including gross plant and accumulated depreciation), the previous average service life estimate, the previous annual depreciation expense, the new annual depreciation expense and the net change.
b) Did Gannett Fleming use empirical data including Iowa curves to determine the need for these changes? If so, please provide the information. If not, please explain.

6.12-Staff-157

Ref: Exh. F5-3-1 Schedule 1A and Schedule 1B

Please provide the account descriptions including the nature of the costs that are recorded in each of the accounts listed in the schedules.

6.12-Staff-158

Ref: Exh. F5-3-1 Schedule 1A and Schedule 1B

For each of the accounts listed in the schedules, please list the names of related sub-ledgers accounts (or sub-accounts or major asset components) and provide the net book value of each sub-ledger account.

6.12-Staff-159

Ref: Exh. F4-1-1 Attachment I and Exh. F5-3-1

Please indicate whether other nuclear operators in North America use the individual "unit method" for end of life estimate rather than the "group method" for nuclear units within nuclear stations. If so, what is the basis for OPG's use of the group method for nuclear units?

6.12-Staff-160

Ref: Exh. F5-3-1 Appendix re Detailed Discussion Related To Niagara Tunnel Lining and D1-2-1 pages 66 to 96

Gannet Fleming states: "The investment in this account relates to the lining material of the Niagara Tunnel that was placed into service in the first quarter of 2013. The 2011 Depreciation Study conducted by Gannett Fleming and internal OPG depreciation reviews have recommended a life estimate of 75 years for the linings associated with the two original tunnels at Niagara Falls. This estimated service life for existing OPG tunnel linings of 75 years is consistent with industry practice."

a) What are the in-service dates for the two original tunnels at Niagara Falls?
b) Please provide a summary of the project information for the two original tunnels at Niagara Falls including the specifications, the lining and estimated useful live.
c) What are the key technological and structural differences between the two original tunnels and the new tunnel at Niagara Falls? Please address the following items in the response in the context of the evidence provided in D1-2-1 pages 66 to 96 for the new tunnel at Niagara Falls: the tunnel lining system, tunnel structures, geological formation, and the major construction components including tunnel construction or boring machine, invert membrane and concrete, arch membrane and concrete, profile restoration and liner grouting.
d) What is the current operating state of the two original tunnels at Niagara Falls?
e) Are the two original tunnels at Niagara Falls expected to be in service for more than 75 years? If not, please provide empirical data and evidence to support this conclusion.
f) Please provide the gross plant asset value and accumulated depreciation of the two original tunnels at Niagara Falls.
g) Is it technologically feasible to refurbish the two existing tunnels and has OPG made this assessment?
h) Is it economically feasible to refurbish the two existing tunnels and has OPG made this assessment?

6.12-Staff-161

Ref: Exh. F5-3-1 Appendix re Detailed Discussion Related To Niagara Tunnel Lining

Gannet Fleming states: "Based on its review of the NTP, it is the view of Gannett Fleming that the tunnel excavation investment would have a similar life of 100 years as expected for the existing two Niagara tunnels and other hydroelectric excavation. However, Gannett Fleming's review also specifically noted that the NTP tunnel lining material installation procedures, were specifically designed and the tunnel was specifically constructed for a service life of 90 years. In fact, the 90-year design life was a specific requirement of the NTP to be considered by contractors working on this project."

a) Why did OPG pick 90-year design life at the onset of this project? Were other number of years assessed, and if so, why they were not chosen?
b) Could 90 years service life be predetermined with any precision in terms of technical design capabilities and structure soundness of the tunnel?
c) What empirical data and evidence does OPG have to support that the tunnel lining would last 90 years, as opposed to 125 years?
d) What is the probability that the pattern of wear and tear of the tunnel would result in an end of life which would be more than 90 years given that advanced technology was used including tunnel construction boring machine, invert membrane and concrete, arch membrane and concrete, profile restoration and liner grouting lining, etc. The tunnel was reinforced with a combination of steel ribs, wire mesh, rock bolts and concrete that varied with the actual rock conditions encountered along the tunnel route, and finally, a waterproof membrane was applied and the final concrete liner was constructed.
e) Have there been any tunnels built worldwide that used a similar design, technology and lining, and if so, what were the expected service lives for these?
f) Please provide reports, studies, memos, letters and presentations which relate to the review, analysis and recommendations for the service life of the new tunnel.

6.12-Staff-162

<u>Ref: Exh. F5-3-1 Appendix re Detailed Discussion Related To Niagara Tunnel Lining</u>

Neither OPG nor Gannet Fleming has indicated that the tunnel lining has a life limiting component to the tunnel to be operational as compared to nuclear stations life limiting components such as the life of pressure tubes. Is the tunnel lining a life limiting component to the overall tunnel? If so, please specify the reasons including comparison to nuclear stations life limiting components.

Income and Property Taxes

Issue 6.13

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

6.13-Staff-163

<u>Ref: Exh. F4-2-1</u>

Please confirm OPG is seeking recovery of income tax expense of $220.6M and $152.3M for the 2014 and 2015 test years respectively.

6.13-Staff-164

<u>Ref: Exh. F4-2-1 and Tables</u>

Please update the evidence in Exh. F4-2-1 including applicable Tables arising from OPG's 2014/15 Payment Amounts Application – Impact Statement (on December 6, 2013) and from the passage of time by replacing "2013 Budget" amounts with "2013 Actual" amounts.

6.13-Staff-165

Ref: Exh. F4-2-1 and Tables 1, 2 and 3

Page 3 states: "For the purpose of determining payment amounts for each regulated business, total income taxes, before SR&ED ITCs, determined for OPG's prescribed facilities are allocated based on each business's regulatory taxable income."
Please provide a detailed calculation showing the derivation of each business's regulatory taxable income in relation to the income tax amounts for 2014 and 2015 in Tables 1, 2 and 3.

6.13-Staff-166

Ref: Exh. F4-2-1 and Table 5

Table 5 at Line 21 in "Regulatory Taxable Income" shows a negative amount of $39.2M (net loss) for 2013 Budget.

a) Please update the 2013 Budget amount to reflect the actual amount for 2013 as at December 31.
b) If the actual amount for 2013 remains as a net loss, is the amount being applied as a loss carry forward to reduce the Regulatory Taxable Income for 2014? If not, please explain.

6.13-Staff-167

Ref: Exh. F4-2-1 and Table 5

Pages 9-10 states: "The balances approved in EB-2012-0002 for the Pension and OPEB Cost Variance Account, the Nuclear Liability Deferral Account and the Impact for USGAAP Deferral Account as at December 31, 2012 contain amounts that do not have a matching tax benefit. As these balances reflect the associated income tax impacts, no adjustment to earnings before tax is made in respect of the recovery of these balances." Table 5 (line 7, col. 8) shows an addition for tax purposes of $21.4M although it is stated that no adjustment to earnings before tax is made in respect of the recovery of this account balance.

Please explain the reason for this amount being added back to the regulatory tax calculation.

6.13-Staff-168

Ref: Exh. F4-2-1

Please provide a summary of the losses incurred and applied to regulatory taxable income in each year from 2010 to 2015.

6.13-Staff-41

Ref: Exh. F4-2-1 pages 2-4 and 10-12

Please provide a summary of the SR&ED Qualifying Capital Expenditures and the SR&ED Investment Tax Credits Recognized in Regulatory Earnings Before Tax incurred and applied to regulatory taxable income in each year from 2010 to 2015.

6.13-Staff-169

Ref: Exh. F4-2-1 pages 10-12

For the SR&ED Qualifying Capital Expenditures which are not deductible effective in 2014, please quantify and provide the related capital expenditures amounts that flowed to income tax Schedule 8 including the UCC and CCA amounts for 2014 and 2015 and provide the related asset class and CCA rate.

6.13-Staff-170

Ref: Exh. F4-2-1 Table 9

Table 9 (col. c) includes $1,227.8M under Net Adjustment and related Note 3 states that these amounts represent the inclusion of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities effective in 2014.

Please provide a schedule (in the format of Table 9) detailing the derivation of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities by year from 2007 to 2013.

6.13-Staff-171

Ref: Exh. F4-2-1 Table 9, Exh. A2-1-1 Attachment 1, Exh. B2-2-1 Table 1

The 2012 Annual Report, Note 15 Business Segment (page 134), shows an amount of $3,310M for the “unregulated hydroelectric” segment property, plant and equipment in-service, net.

a) Please confirm whether the $3,310M amount represents the equivalent of “newly” regulated hydroelectric facilities in 2012, and if not, please provide this amount.
b) In March 2013, OPG would have released its 2013 financial results including its 2013 consolidated financial statements which will also provide the 2013 amount for the “unregulated hydroelectric” segment property, plant and equipment in-service, net. Please confirm whether the 2013 amount represents the equivalent of “newly” regulated hydroelectric facilities in 2013, and if not, please provide this amount.
c) Table 9 (col. c) of Exh. F4-2-1 includes $1,227.8M under Net Adjustment which represents the inclusion of the Undepreciated Capital Cost for the newly regulated hydroelectric facilities effective in 2014. Please provide a reconciliation of the $3,310M for the 2012 “unregulated hydroelectric” segment reported, or as adjusted, and the $1,227.8M for the 2014 Undepreciated Capital Cost. However, if the information requested in b) above is available, please provide a reconciliation of the 2013 “unregulated hydroelectric” segment reported, or as adjusted, and the $1,227.8M for the 2014 Undepreciated Capital Cost, instead.
d) Table 9 (col. c) of Exh. F4-2-1 shows $1,227.8M under Net Adjustment as an inclusion to the Undepreciated Capital Cost (UCC) for the newly regulated hydroelectric facilities effective in 2014. Table 1 (col. g) of Exh B2-2-1 shows rate base of $2,511.5M for the newly regulated hydroelectric. Please provide a reconciliation of the $2,511.5M rate base for the newly regulated hydroelectric in 2014 and the $1,227.8M UCC for 2014.

6.13-Staff-172
Ref: Exh. F4-2-1 Table 2
With respect to the newly regulated hydroelectric facilities, are there any SR&ED Investment Tax Credits or loss carry forward amounts arising in prior years available to be applied to income taxes in the test period? If no please explain. If yes, please identify these amounts and how they were applied.

Other Costs

Issue 6.14
Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate?

Asset Service Fees

6.14-Staff-173
Ref: Exh F3-2-2
The application notes the asset service fee remains stable. In terms of nuclear, for the most part, they are quite stable from year to year. However, in the 2015 test year, there is an increase of 18% relative to the 2013 bridge year. The application notes that increase is primarily due to higher IT additions and IT depreciation with no further explanation. Please provide a more detailed explanation regarding the IT addition that resulted in the deviation from the stable trend that occurs in 2015 including the total cost and the associated amount allocated to regulated operations.

6.14-Staff-174
Ref: Exh F3-2-1
The application discusses Joint Use Hydroelectric Assets which support both newly regulated and unregulated hydro stations (i.e., under OPA contracts). The application notes that, under the asset service fee approach, such assets are not included in rate base. Instead, the regulated and unregulated facilities are charged a service fee which is included in their respective OM&A expenses.

a) Is Board staff's understanding correct that, if the capacity of newly regulated stations serviced by a 'shared' asset exceeds a threshold (referred to as "dominant use"), the 'entire' cost is attributed to regulated operations and is also included in rate base?
b) If so, why does OPG believe including costs associated with the unregulated hydro stations in the regulated payments is more appropriate than consistently applying the asset service fee methodology to all joint use assets by allocating the costs based on the relative capacity of the regulated and unregulated stations that use the asset and not including the asset in rate base?

OTHER REVENUES

Regulated Hydroelectric

Issue 7.1
Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

7.1-Staff-175
Ref: Exh G1-1-1 page 5
OPG states: "With the addition of the Niagara Tunnel, OPG's diversion capability increased to approximately 2,400 cubic meters/second. The increase in water utilization will result in significantly decreased WT volumes."

c) Since the Niagara Tunnel went into service what has been the actual increase in water utilization?
d) What would be the change in WT volumes over the 2009 to 2011 period (the period OPG used in its analysis of potential volume decreases) if the actual utilization rate was used instead of the "capable rate"?
e) What percentage decrease in WT volumes would this actual diversion rate represent?

7.1-Staff-176
Ref: Exh G1-1-1 Table 1
OPG's evidence discusses the various types of ancillary services provided by OPG and the contract provisions with the IESO.

a) What are the pricing provisions in the black start, reactive support/voltage control service, and regulation service contracts with the IESO?
b) Are contract prices fixed over the test period or are there provisions for escalation based on an index or a market-determined price, i.e., HOEP?
c) Operating reserve (OR) is a market-based sale with prices determined by the IESO. OPG assumes that revenues in the test period will be an inflationary increase of the 2012 actual revenues.
    i. Are OPG's revenue estimates for OR based on no increase in OR services provided and strictly an inflationary price increase?
    ii. What evidence does OPG have that historical changes in OR prices are correlated with OPG's BP inflation measures?
d) Please provide a table with the estimated test period revenues by service provided instead of an aggregate for all services.

Bruce Nuclear Generating Station

Issue 7.3
Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

7.3-Staff-177
Ref: Exh. G2-2-1 Pages 3-5
In respect of the partial rebate for supplemental rent revenue in relation to the Bruce derivative used for accounting purposes:

a) Has the condition in the Bruce Lease of an "Average HOEP falling below $30/MWh" been triggered in 2013 to give rise to a recognition of an adjustment to the fair value of the derivative liability and revenue in 2013?
b) If so, please provide the changes in the fair value of the derivative and associated income tax impacts on Bruce Lease net revenues.

7.3-Staff-178
Ref: Exh. G2-2-1 Pages 3-5 and Tables 1, 3 and 5
Exh H1-3-1 pages 12-13
Regarding the partial rebate for supplemental rent revenue in relation to the Bruce derivative, if there are changes in the fair value of the derivative and associated income tax impacts on Bruce Lease net revenues effective from 2013:

a) Does OPG intend to reduce the Bruce revenue to the extent of the changes in the fair value of the derivative in any given year?
b) If so, would OPG adopt a similar procedure used for the Bruce Lease Net Revenues Variance Account for the derivative portion? This amount would be offset by the difference in the cumulative amount recovered from ratepayers for the derivative portion since April 1, 2008 and cumulative amount of actual rent rebates and associated income taxes incurred by OPG since April 1, 2008. If not, please explain.

7.3-Staff-179
Ref: Exh G2-2-1 Table 4 and Exh C1-1-1 Tables 3 and 4
Exh C1-1-1 Tables 3 set out the ARO Adjustment of $1,363.5M arising from the approved Ontario Nuclear Funds Agreement ("ONFA") Reference Plan effective January 1, 2012, which was also reviewed and approved for ratemaking in the EB-2012-008 proceeding. However, with respect to Bruce Net Fixed Assets per Exh C1-1-1 Tables 4 (line 14, column g), an amount of $725.6M for 2012 was added instead of the approved amount of $706.6M per Exh C1-1-1 Tables 3 (line 2, column c).

Exh C1-1-1 Table 4 (line 4, column d) "New CNSC Requirements Adjustment" of $19.5M is explained in Note 4 as follows:

> Represents implementation, in accordance with GAAP, of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licenses not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC. As a result, ARO increased by $2.4M to include a legacy facility not used to support OPG's current operations, of which $1.3M is attributed to prescribed facilities and $1.1M is attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) in 2012. ARO increased by a further $19.5M to include a facility dedicated to supporting the Bruce facilities. In accordance with GAAP, this amount was included in ARC.

It appears that this incremental adjustment is outside the scope of the government approved ONFA Reference Plan or the Board approved amounts shown in Exh C1-1-1

Tables 3. If this is the case, please adjust the Bruce Net Fixed Assets Exh C1-1-1 Tables 4 (line 14, column g) to reflect $706.6M and make the consequential adjustments accordingly.

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

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

8.2-Staff-180
Ref: Exh. C2-4-1 Table 1a Note 3 line 4c
Please explain why deferred income taxes - long-term are calculated for the following items with respect to the Bruce facilities and also indicate if these items were included in deferred income taxes in the last payment order:

- Used Fuel Storage and Disposal Variable Expenses
- Low & Intermediate Level Waste Management Variable Expenses
- Accretion Expense
- Segregated Fund Earnings (Losses)

8.2-Staff-181
Ref: Exh. C2-4-1 Table 5
Please provide detailed calculations showing the derivation of all the line item amounts in columns (a) and (b) except for lines 6, 7, 8, 15, 16, 17 and 18.

DEFERRAL AND VARIANCE ACCOUNTS

Issue 9.2
Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.2-Staff-182
Ref: Exh. H1-1-1 page 7 and Tables 1 and 12 and Exh. H1-2-1 Table 2
With respect to the Capacity Refurbishment Variance Account, OPG states “Table 12 also presents the projected 2013 nuclear non-capital cost account additions, which OPG is not seeking to clear in this application.” The EB-2012-0002 proceeding determined that this account would be cleared in the next payment proceeding.

a) Please confirm that OPG is not seeking to recover either the total nuclear non-capital cost projected account balance of $25.4M or the projected nuclear non-capital cost account additions (transactions) of $20.6M as at the 2013 year-end 2013.
b) Please provide the reasons for not clearing the identified amount noted above in this proceeding.

9.2-Staff-183

Ref: Exh H1-1-1 page 12 and Table 11 and Exh. F2-8-1 page 5, Table 1

With respect to the Nuclear Development Variance Account,

a) For the projected 2013 recorded transactions of $38.6M, does this amount include only incremental labour costs which were clearly not included in approved OM&A costs in the last payment proceeding?
b) For the labour costs in 2011, 2012 and 2013, please provide a detailed breakdown of the costs for each year by their nature and purpose, the amounts, the suppliers and proof of payments to parties.

9.2-Staff-184

Ref: Exh. H1-1-1 page 12 and Table 11

With respect to the Nuclear Development Variance Account,

a) Please explain why OPG is seeking to recover from ratepayers the amounts recorded in the Nuclear Development Variance Account given that the planned new nuclear plants are being discontinued.
b) Please provide any regulatory precedents that have allowed development costs to be recovered for discontinued development of facilities.

9.2-Staff-185

Ref: Exh. H1-1-1 Table 7

Please provide a detailed calculation showing the derivations of the 2013 projected amounts (to be updated to reflect 2013 actual, if applicable) for “Increase Regulatory Taxable Income” (line 8 column c) and Niagara Tunnel Project - Income Tax Impact (line 9 column c).

9.2-Staff-186

Ref: Exh. H1-1-1 Table 12a

Please provide a detailed calculation showing the derivations of the 2013 projected amounts (to be updated to reflect 2013 actual, if applicable) for “Increase Regulatory Taxable Income” (line 8 column c) and “Total Capital Addition to Variance Account” (line 11column c).

9.2-Staff-187

Ref: Exh. H1-1-1 Table 5 (line 1 columns b and c) and Exh. E1-2-1 Page 3

With respect to the foregone production due to surplus baseload generation (SBG) conditions, please explain why the SBG spill volume for 2013 is projected to be 178.0 GWh (to be updated to reflect 2013 actual), which is 52 percent higher than the 116.9 GWh for 2012.

9.2-Staff-188

Ref: Exh. H1-1-1 Table 5 (line 3 columns a, b and c)

Please provide a detailed breakdown of the derivations of the Gross Revenue Charge/Water Rental Costs of $(1.1)M for 2011, $(1.7)M for 2012 and $(2.6)M for 2013.

9.2-Staff-189

Ref: Exh. H1-1-1 Table 5 (line 5), Table 7 (line 15), Table 12a (line 12)

The referenced tables in the specified lines are entitled “Financial Reporting Adjustment” and their associated footnotes state: “Represents offsetting interperiod financial statement reconciliation adjustments which do not impact the total transactions in the account over the 2011-2012 period.”

a) Please provide an explanation for and identify of the nature of the “Financial Reporting Adjustment” for each of the lines noted-above in relation to the specific tables.
b) Was the “Financial Reporting Adjustment” for each account’s balance reflected in OPGs financial statements including the nature of accounting adjustments and any note disclosures? If so, please provide the details.

Issue 9.5
Is the proposed continuation of deferral and variance accounts appropriate?

9.5-Staff-190

Ref: Exh. H1-3-1 pages 12-13

Regarding the Bruce Lease Net Revenues Variance Account,

a) As the basis for its continuation, please confirm that the operation and accounting procedures including the disposition mechanism of the account is consistent with the approved Settlement Agreement reflected in the EB-2012-0002 Payment Amounts Order.
b) Please confirm that the operation and accounting procedures including the disposition mechanism of the account is ongoing effective January 1, 2013.

Issue 9.6
Is OPG’s proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

9.6-Staff-191

Ref: Exh. H1-2-1 Tables 1 and 2

In cost of service proceedings, the Board’s policy generally requires utilities to bring forward all balances in deferral and variance accounts for review and disposition. Please provide the reasons all accounts other than the four required by the decision and order in last the proceeding (EB-2012-0002) are not being proposed for clearance in this proceeding.

9.6-Staff-192

Ref: Exh. H1-2-1 Tables 1 and 2

Please provide revised rate riders based on the disposition of all balances in deferral and variance accounts consistent with the recovery period used in Tables 1 and 2 of

Exh H1-2-1. In addition, please provide the revised bill impact on customers consuming electricity of 800 kWh/month.

Issue 9.7
Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

9.7-Staff-193
Ref: Exh. H1-3-1 pages 1-15
Regarding the proposal to make the existing variance accounts applicable to the newly regulated hydroelectric facilities,

a) Please provide a detailed explanation on how each account meets the Broad's qualification criteria of:
    i. Materiality
    ii. Causation
    iii. Prudence
    iv. Outside of Management's ability to control
b) Please explain why the proposal for the accounts should be included and operate as part of existing hydroelectric facilities.
c) If approved, will OPG report to the Board the specific balances of the sub-accounts within the existing hydroelectric variance accounts for greater transparency (rather than the rolled-up sub-account balances shown as one figure for each applicable account)? If not, please explain.

9.7-Staff-194
Ref: Exh. H1-3-1 pages 1-15
For the proposal to make existing variance accounts applicable to the newly regulated hydroelectric facilities, please identify whether any accounts are required to be established under Ontario Regulation 312/13, and if so, provide the relevant section for each.

9.7-Staff-195
Ref: Exh. H1-3-1 pages 1-15
Please provide a historic variance analysis in table format consisting of years 2010, 2012 and 2013 for each of the proposed production-based deferral or variance accounts of the newly regulated hydroelectric facilities (i.e., not including the Income and Other Taxes Variance Account and the Pension & OPEBs Variance Account) as follows:

a) The production forecast (MWh) for each year determined by OPG's production forecast models (i.e., forecast prior to the start of the year)
b) The actual production (MWh) for each year (included in the consolidated audited financial statements)
c) The production variance (MWh) between a) and b) above for each year
d) The financial impact applying the variance (MWh) in c) above multiplied by the payment amount ($/MWh) for newly regulated hydroelectric facilities requested in this application.

9.7-Staff-196
Ref: Exh. H1-3-1 pp 1-15
In the context of the IESO administered electricity spot market,

a) Please indicate the nature of the newly regulated hydroelectric facilities in terms of their name plate capacities and the conditions under which they generally operate in the electricity market (e.g., to serve base load, peak, etc.).
b) Will the newly regulated hydroelectric facilities continue to operate in the same manner in the electricity spot market notwithstanding they will have regulated prices?
c) Is there more or less incentive to produce and supply electricity for dispatching to the spot market given that the prices are regulated and no longer tied to spot market price?

Issue 9.8
Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

9.8-Staff-197
Ref: Exh H1-3-1 page 5 and Exh E1-2-1
OPG is proposing a change to the operation of the HIM that eliminates the need for additions to the account in the future. However, please provide the reasons why this account should not continue with appropriate modifications, if applicable, in order to test the results of the proposed mechanism discussed in Exh E1-2-1 until the next payment order proceeding?

METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Issue 11.1
Has OPG responded appropriately to Board direction on establishing incentive regulation?

11.1-Staff-198
Ref: Exh A3-1-1 page 2, Exh A3-1-1 Attachment 1 page 6
Regarding the current status of the productivity study, OPG documents the following:

> As contemplated in the attached work plan, LEI [London Economic Inc.] has commenced its literature review and begun to identify the challenges associated with conducting a productivity study for OPG's prescribed hydroelectric facilities.

This evidence is of the date of filing of OPG's application on September 27, 2013.

a) As noted on pages 1 and 2 of this exhibit, LEI was engaged by OPG and participated in the consultative process that culminated in the *Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Assets (EB-2012-0340)*. LEI is an international energy consulting firm, and also has had involvement in the Ontario electricity sector for over 10 years. Given LEI's experience both internationally and in Ontario, what is the nature of the literature review, and why does it indicate that it will require work from 2013 Q3 to 2014 Q1 as documented in Figure 1 on page 6 of LEI's Work Plan (Exh A3-1-1 Attachment 1)?

b) What is the current status of LEI's work, and how is OPG monitoring this work?

11.1-Staff-199

Ref: Exh A3-1-1 Attachment 1 page 4

On page 4 of LEI's Work Plan, LEI states:

> LEI proposes to assist OPG in performing a productivity study. However, in recognition of the data issues that have been discussed previously, **LEI anticipates that the work plan would not presume from the start that the productivity study would be sufficiently robust to be successfully deployed for ratemaking in an IR mechanism.** It will be important for the productivity study to include documentation of the study process, including the obstacles, workarounds, and simplifications, as such documentation will provide valuable context for OPG and stakeholders, regarding the limitations and applications of the productivity study results. **[Emphasis added]**

The Board's interest in exploring IRM mechanisms for setting payments for OPG's prescribed generation assets has been expressly known since the Board first started its review of regulatory options for OPG (EB-2006-0064). Please explain why LEI presumes that a productivity study of prescribed hydroelectric generation would not be robust enough to be successfully deployed for rate-making as part of an IRM plan at this point in time.

11.1-Staff-200

Ref: Exh A3-1-1 Attachment 1 page 2

The issue of moving to some form of incentive rate-making mechanism has been raised conceptually in previous OPG payments applications. The form of IRM would pertain to the prescribed nuclear and hydro-electric assets.

In the *Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Assets (EB-2012-0340)*, the Board found that IRM may, at this point in time, be better directed with respect to the then prescribed hydro-electric assets of the Robert H. Saunders St. Lawrence hydroelectric GS and the Niagara plant hydroelectric group.

On page 2 of LEI's Work Plan, LEI notes the expected (at that time) amendment of O.Reg. 535/05 for the newly regulated hydro-electric assets of the 48 named smaller hydro-electric generating stations. O.Reg. 312/13 amending O.Reg. 535/05 was filed on November 29, 2013 and comes into effect on July 1, 2014.

LEI's Work Plan filed as Exh A3-1-1 Attachment 1 notes the newly prescribed hydroelectric assets, but does not otherwise discuss how this is to be dealt with in the productivity work.

a) What are OPG's plans or proposals with respect to inclusion or exclusion of the newly regulated hydroelectric assets for any productivity study or for any form of IRM rate-setting mechanism? Please explain the rationale for your proposal.
b) What instructions has OPG provided to LEI, or what is LEI's proposal, with respect to inclusion or exclusion of the newly regulated hydroelectric assets in the work planned for in Exh A3-1-1 Attachment 1?