OPG

EB-2016-0152

OEB Staff Compendium

Panel 5B

informing the public with respect to the progress of the project, it also is informing its regulator with respect to the project degree of sophistication that's appropriate for the regulator to be able to understand where things are and are not.

And I think -- so, first and foremost, it's obviously for information purposes. It's not -- and it's not anywhere in the application contemplated to act at some form of regulatory basis upon which to form part of any future consideration. Otherwise, those -- that aspect would be dealt with, as people have already testified, on future applications or dealings with respect to deferral and variance accounts.

But I think that is really the measure of it, I think, at least in terms of what the filing contains.

MR. RICHLER: Thank you.

This question may be better for another panel. If so, you can tell me. I'm wondering if OPG has some sort of rule of thumb to guestimate the revenue-requirement impact of any DRP-related addition to rate base. For example, is there 10 percent rule of thumb or some other percentage?

MR. KEIZER: I don't think that's for this panel. I think it's panel 5 would be the best place to ask that question.

MR. RICHLER: That's fine.

I understand that, for all projects at Darlington, including DRP, work is completed under what you call work protection, which I take it means ensuring that equipment refurbishments that resulted in some substantial improvements to the tooling. And that required -- that required engineering and design work that then got implemented into this set of tools for Darlington, so this is a specific Darlington set of tools.

MR. RICHLER: All right. Can you turn to the very last page of the compendium, please? This is Exhibit -- or from Exhibit D2-2-A, attachment 1, an OPG document called:

"Darlington Refurbishment Execution Phase Business Case Summary."

And it says in the second-last paragraph on this page:

"Insurance premiums of $116 million are included in the estimate to purchase coverage to mitigate some of the financial risks. These cover course of construction property, wrap-up liability, marine cargo, and advance loss of property, nuclear energy physical damage property, and delayed start-up."

Do you see where I'm reading from?

MR. REINER: Yes.

MR. RICHLER: Is insurance discussed elsewhere in this application, because I couldn't find anything?

MR. ROSE: Other than it being -- I think it's noted as a cost in our cost breakdown, but maybe not discussed extensively, no.

MR. RICHLER: Did OPG purchase any insurance that would protect it against DRP overruns or delays? Does anything like that even exist in the market?

MR. ROSE: There were a number of insurances, types of insurance, that were considered for the DRP. One of those that were considered was delayed start-up insurance. I'm just not -- I'm not exactly familiar with the final outcome of that insurance process and the insurance that we did ultimately retain.

MR. RICHLER: Is there someone on a later panel who would be more familiar with that process?

MR. REINER: It is run through our finance organization, and the finance panel may be able to address this.

MR. RICHLER: Do you know if OPG got any expert advice on insurance?

MR. REINER: There was, I believe, advice received on insurance. Again, it would have been run through our corporate finance organization.

MR. RICHLER: So any follow-up questions should be saved for them?

MR. REINER: Yeah. That's what I would propose, unless there are specific details in relation to policies that --

MS. LONG: Well, Mr. Reiner, do you know what this $116 million is for?

MR. REINER: It is for insurance. What --

MS. LONG: And -- but you don't know the details --

MR. REINER: I don't know the exact --

MS. LONG: -- with respect to how it relates to the Darlington refurbishment project?

MR. REINER: It is specifically insurance coverage to address potential issues associated with the Darlington refurbishment. What I'm not familiar with is -- so it would be things like damage to physical property caused by a contractor. That would be one element of what the coverage is in there. I know that we did also look at a delayed start-up coverage.

What I don't know off-hand is precisely what coverage does the insurance provide for. And either the finance panel would be able to address that, or we would have to undertake to provide that to you.

MS. LONG: Maybe, Mr. Richler, you can ask the questions of the finance panel, and if the finance panel doesn't know the answers to the specifics of how that would relate to the Darlington project, we can get an undertaking that you could answer those questions -- or someone on this panel could answer those questions.

MR. RICHLER: Yes.

MS. LONG: That's the best way to deal with it.

MR. KEIZER: That's fine, Madam Chair.

MR. RICHLER: Thank you, Madam Chair.

Can we go to page 52 of the compendium, please? This is the beginning of an excerpt from the Technical Conference transcript. There is a discussion between Mr. Rose and Ms. Grice about the difference between the P50 schedule and the P90 schedule for the DRP. And I understand your answer on page 53, Mr. Rose, to confirm that the difference between P50 and P90 for the four-unit

Numbers may not add due to rounding.

Table 3

Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	Costs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Pension/OPEB Related Accrual Costs**	289.0	298.5	343.0	200.1	106.6	65.9	42.9	26.5	16.8
2	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences**[1]	0.0	0.0	0.0	0.0	(145.4)	(82.1)	(59.5)	(65.7)	(49.8)
3	**OPG-Wide Insurance**	3.3	3.4	4.6	6.2	6.4	6.5	7.0	7.0	6.8
4	**Nuclear Insurance**	7.6	8.0	8.2	19.1	21.1	23.1	26.1	26.5	27.1
5	**Performance Incentives**	14.5	20.2	17.1	18.4	18.4	18.5	18.6	18.5	18.5
6	**IESO Non-Energy Charges**	57.4	51.2	77.7	62.1	61.1	56.5	51.8	54.5	42.0
7	**Other**	38.1	29.7	9.4	21.0	6.7	24.5	16.0	18.3	14.3
8	**Total**	409.9	411.0	459.9	326.9	74.9	112.9	102.9	85.7	75.7

Notes:

1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the test period adjustment is included to reflect OPG's proposal to include cash amounts for pension and OPEB in the nuclear revenue requirement and defer the difference between accrual costs and cash amounts in the Pension & OPEB Cash to Accrual Differential Deferral Account pending the outcome of the EB-2015-0040 generic consultation, consistent with the EB-2013-0321 treatment.
The difference between accrual costs and cash amounts is found in Ex. F4-3-2 Chart 3.

3.4 Commercial Operations and Environment

Commercial Operations and Environment includes Commercial Contracts, Environment, Regulatory Affairs, Electricity Sales and Trading, and Integrated Revenue Planning sections.

OPG recently restructured Commercial Operations and Environment by transferring Commercial Contracts, Environment, Regulatory Affairs, Electricity Sales and Trading and Integrated Revenue Planning groups to different divisions within the organization. Despite changes in organizational structure and reporting relationships, OPG continues to present costs as if Commercial Operations and Environment remained intact. Presenting costs in this way allows for ease of comparability between historical, bridge and test years, provides continuity with previous filings and is consistent with the presentation in OPG's approved 2016-2018 Business Plan (Ex. A2-2-1 Attachment 1). The changes in organizational structure do not have a material impact on the costs forecast for the bridge year and test period and do not have an impact on the cost allocation methodology.

<u>Commercial Contracts</u>

Commercial Contracts includes Fuels, Commercial Services, and Bruce Lease Management departments. The Fuels department is responsible for the procurement and delivery of fuel (excluding uranium), sales of by-products, acquisition of emission allowances and credits, negotiation and contract management for generation and ancillary services with the Independent Electricity System Operator ("IESO"). Commercial Services markets and manages a program for the sale of isotopes and heavy water products, and services for existing and future applications. Bruce Lease Management Office manages contracts with Bruce Power.

<u>Environment</u>

Environment provides operational support to OPG plants and facilities to minimize environmental risks and impacts, reports on OPG's environmental performance, provides environmental assessment and specialist support and seeks opportunities for

3.5 Corporate Centre

The corporate centre includes: the Executive Office (Chairman, President and CEO offices); Corporate Executive Operations; Law; Corporate Relations and Communications; Corporate Business Development and Enterprise Risk Management; and Assurance.

OPG recently restructured Corporate Centre by transferring Law, Corporate Relations and Communications and Corporate Business Development and Enterprise Risk Management groups to different divisions within the organization. Despite the changes in organizational structure and reporting relationships, OPG continues to present costs as if Corporate Centre remained intact. Presenting costs in this way allows for ease of comparability between historical, bridge and test years, provides continuity with previous filings and is consistent with the presentation in OPG's approved 2016-2018 Business Plan (Ex. A2-2-1 Attachment 1). The changes in organizational structure do not have a material impact on the costs forecast for the bridge year and test period and do not have an impact on the cost allocation methodology.

Executive Office

The Executive Office is responsible for the overall management and strategy of the company.

Corporate Executive Operations

The Corporate Executive Operations function supports OPG's Board of Directors and the Executive Office, and interfaces between the OPG Board, management and OPG's shareholder.

Law

Law provides legal advice and services to support all business units across OPG, including support for various procurement activities and corporate and commercial matters. Law provides advice related to OPG's pension and nuclear funds; real estate; Bruce lease and related agreements and water resources; municipal approvals and land

HR, number of employees was used to benchmark costs per employee. For Finance and Executive and Corporate Services ("ECS"), revenues were used to benchmark costs as a percentage of revenues.

The benchmarking study found that OPG's regulated corporate function costs declined 10 per cent from 2010 to 2014 while total regulated OPG headcount declined 11 per cent. It also found that OPG's overall cost benchmark performance at the functional level improved between 2010 and 2014 while comparisons to peer benchmarks varied by function, as shown in Figure 1.

Figure 1: Summary of Corporate Cost Benchmarking Results

Line No.	Corporate Function	OPG 2010 (a)	OPG 2014 (b)	Peer (c)	OPG Improvement 2010 - 2014 (%) (d)
1	IT Cost per End User	$12,015	$9,541	$14,995	21%
2	HR Cost per Employee	$3,400	$3,375	$3,350	1%
3	Finance Cost as a Percent of Revenue	1.02%	0.75%	0.66%	26%
4	ECS Cost as a Percent of Revenue	3.39%	2.75%	1.07%	19%

As shown in Figure 1:

- OPG's IT cost per end user decreased between 2010 and 2014 by 21 per cent and was 36 per cent less than the peer benchmark
- OPG's HR cost per employee remained relatively flat between 2010 and 2014 and was in closer proximity to the peer benchmark
- OPG's Finance cost as a percentage of revenue significantly closed the gap to peer decreasing by approximately 26 per cent between 2010 and 2014.
- OPG's ECS cost as a percentage of revenue was reduced by approximately 19 per cent between 2010 and 2014. ECS is comprised of 11 diverse sub-categories.[1]

[1] The 11 sub-categories are: Administrative Services, Transportation Services, Real Estate and Facilities Management, Government Affairs, Legal (includes Regulatory Affairs), Quality Management, Risk

stretch factor proposal provides a meaningful performance incentive during the term of this Application. The proposed stretch reductions are in addition to efficiencies and performance improvements within the company's business planning processes.

Exhibit F3-1-1 Table 3 presents the Support Services costs assigned and allocated to nuclear over the historical, bridge, and test years. Performance initiatives incorporated into the business planning process and the corresponding performance and operational efficiency improvements are reflected in the forecast expenditures in this Application. The Support Services costs shown in this Exhibit do not reflect application of the stretch factor, which is shown separately in Ex. A1-3-2.

3.1 Business and Administrative Services

BAS manages the following functions: Information Technology, Real Estate, and Supply Chain. The BAS functions have not changed since EB-2013-0321.

Information Technology ("IT")

The IT group oversees OPG's information management and information technology needs. IT is accountable for the strategic planning, management and operations of all business and technical information systems, but does not support process computers that control plant systems and operations. IT also administers OPG's information management and governing documents framework.

Information technology services are provided through a combination of internal staff and an outsource service contract with New Horizon System Solutions ("NHSS"), owned by Capgemini. NHSS delivers application and infrastructure management services across OPG. OPG IT provides application management services to Commercial Operations due to the commercially sensitive nature of the applications, as well as specific infrastructure and application management services to staff at the hydroelectric sites.

Exhibit F3-1-1 Table 7 presents BAS costs that are assigned and allocated to nuclear over the historical, bridge, and test years. The costs related to NHSS services, which

Benchmark Methodology

Data Guidelines and Benchmark Scope

- Geographic Scope:
    - All OPG regulated operations
- Benchmark data collection period = Fiscal Year 2010 and 2014
- All data is represented in 2014 Canadian Dollars for comparison purposes
    - PPP (Purchasing Power Parity) was used to adjust the peer data from US to Canadian dollars
    - A 2%/year inflation rate was applied to the peer companies and OPG's 2010 costs/revenue to normalize the data to 2014 Canadian Dollars
- Out of Scope – The below items were not included in the benchmark to facilitate an apples to apples comparisons to the peer
    - All offices or operations of the unregulated portion of OPG
    - Direct functions of the Darlington Refurbishment Project
    - Integrated Revenue Planning, Electricity Sales & Trading, Commercial Contracts and Corporate Business Development
    - For Finance: Revenue cycle, Fund Management, nuclear-specific costs (e.g., nuclear insurance)
    - For Human Resources: Workforce Development Services (training)
    - For Executive and Corporate Services (ECS): Security, Cafeteria and Catering, Travel Services, Legal – Mergers and Acquisitions (M&A), nuclear-specific costs (e.g. nuclear facilities costs); Within Procurement, warehouse management & logistics and product development, design & support

Benchmark Comparisons

- **Peer Group –** represents the median of a custom group of companies in multiple industries that have similar size and business complexity to OPG

Normalization of Benchmark Data

- Data has been normalized based on the key demand drivers for each function:
    - Finance, ECS = Revenue ($4.237B in 2010 and $4.849B in 2014)
    - IT = End User Equivalents (11,011 in 2010, 12,267 in 2014)
    - HR = Employees (10,305 in 2010 and 9,292 in 2014)

Revenue: *External Revenue Only, intercompany revenue not included. OPG includes revenue associated with regulated operations only. OPG revenue is adjusted to account for revenue deferred to future periods and to include revenue in 2010 from newly regulated hydroelectric facilities to facilitate transparent comparison before and after OPG's Business Transformation initiative.*
Employees: *Full-time, part-time, seasonal, and contingent employees . OPG includes employees associated with regulated operations only.*
End User: *An individual (typically either an employee or contractor) that spends at least 10% of his or her time using a company provided, funded, supported computing device that is part of the company's IT infrastructure (i.e. desktops, laptops, hand held devices, etc.) to support his or her business function. The user must have direct access to internal applications / systems to execute specific transactions on behalf of the company. OPG includes end users associated with regulated operations only.*

The Hackett Group

Hackett has a robust and well-defined taxonomy

General & Administrative Scope (G&A)

Finance

- Accounts Payable; Travel & Expenses
- Credit, Customer Billing, Collections, Dispute Management, Cash Application
- General Ledger, Enterprise Consolidation, Intercompany & Cost Accounting, Fixed Assets, External Reporting
- Tax Management
- Cash, Capital & Risk Management
- Compliance Management
- Strategic Business Planning Support, Annual Planning, Forecasting, Business Performance Reporting
- Business Analysis
- Function Management

HR

- Health & Welfare, Pension & Savings, Compensation Administration
- Payroll, Time & Attendance
- Employee Data Mgmt. and HR Reporting, Compliance Management
- Recruiting & Staffing, Exit Process
- Transferable, Non-transferable Skills
- Organization Design & Development, Employee Relations
- Labor Relations
- Total Rewards Planning
- Strategic Workforce Planning
- Function Management

IT

- IT Business Planning
- Enterprise Architecture Planning
- Emerging Technologies
- Infrastructure Development
- Application Development
- Quality Assurance
- Infrastructure Management
- End User Support
- Application Maintenance
- Risk and Function Management

Executive & Corporate Services (ECS)

- Administrative Services
- Travel and Transportation Services
- Real Estate & Facilities Management
- Government Affairs
- Legal
- Quality Management
- Risk, Environment Health and Safety, and Security Management
- Corporate Communications
- Planning and Strategy
- Executive Office
- Procurement

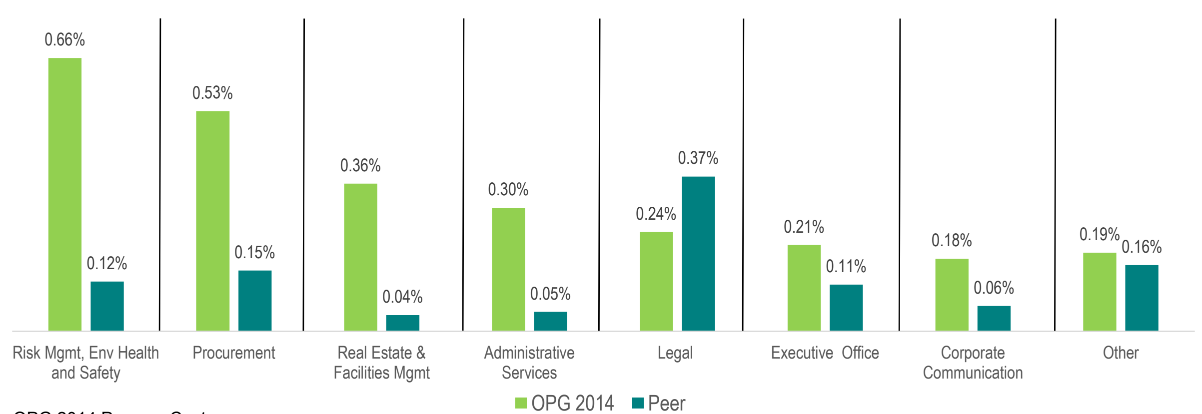
Hackett's process taxonomy is applied independent of OPG's organizational structure and functional reporting lines, thereby facilitating an "apples-to-apples" comparison

Functions in grey font were excluded from the benchmark

The Hackett Group

OPG ECS has opportunities to peer especially in the areas of Risk Management and EHS, Procurement, and Real Estate

ECS Process Cost as a Percent of Revenue



OPG 2014 Process Costs:

Risk Management, Env. Health and Safety	Procurement	Real Estate & Facilities Management	Admin Services	Legal	Executive Office	Corporate Communication	Other
32.3	25.8	17.3	14.5	11.9	10.1	8.5	9.2

*Numbers may not sum due to rounding
*Real Estate and Facilities Management: OPG's cost for this sub-category includes all facility costs associated with corporate regulated operations including facility costs associated with IT, HR, and Finance functions. Such facility costs are embedded in each particular function for OPG's peer
*Other processes include: Transportation, Quality Management, Government Affairs, and Planning and Strategy

The Hackett Group

Board Staff Interrogatory #169

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

Interrogatory

Reference:
Ref: Exh F3-1-1 page 14
Ref: EB-2010-0008 Exh F5-3-2

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

a) Are the peer results at column (c) at 2014?

b) In EB-2010-0008, OPG filed a Finance benchmarking report prepared by the Hackett Group. The report included reporting by peer group quartiles. What was OPG's performance by quartile for each corporate function in 2010 and 2014?

c) For the 2017-2021 test period, please provide IT cost per end user, HR cost per employee, finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue.

Response

a) As shown in Ex. F3-1-1, Attachment 1, p. 6, all data is represented in 2014 Canadian Dollars for comparison purposes.
   - PPP (Purchasing Power Parity) was used to adjust the peer data from US to Canadian Dollars
   - A 2%/year inflation rate was applied to the peer companies and OPG's 2010 costs/revenue to normalize the data to 2014 Canadian Dollars

b) Attachment 1 to this response is OPG's performance by quartile as provided by the Hackett Group. Note, Attachment 1 is marked "confidential", however, OPG has determined this attachment to be non-confidential in its entirety.

c) Referring to the 2014 values at Ex. F3-1-1, Attachment 1, and forecasted corporate costs in Ex. F3-1-1, OPG has completed a high level estimate of the HR cost per employee, finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue for OPG's nuclear business for 2017-2021, as illustrated in Chart 1 below. IT cost per end user is not included as OPG does not forecast end users.

   Chart 1: Estimate of 2017-2021 HR cost per employee, Finance cost as a percent of forecast revenue and ECS cost as a percent of forecast revenue, for OPG's nuclear business.

	2017	2018	2019	2020	2021
HR per employee	$2,659	$2,661	$2,695	$2,781	$2,839
ECS as a %	2.84	2.85	2.95	2.58	2.81
Finance as a %	0.78	0.78	0.81	0.71	0.77

OPG notes that the values indicated in Chart 1 above represent an estimate based on information available to OPG, and have not been derived using the Hackett Group's taxonomy applied to 2010 and 2014 costs, or otherwise vigorously vetted by a similar taxonomy, as this is not an exercise OPG performs in its normal course of business.

The Hackett Group
World Class Defined and Enabled

ONTARIO POWER GENERATION

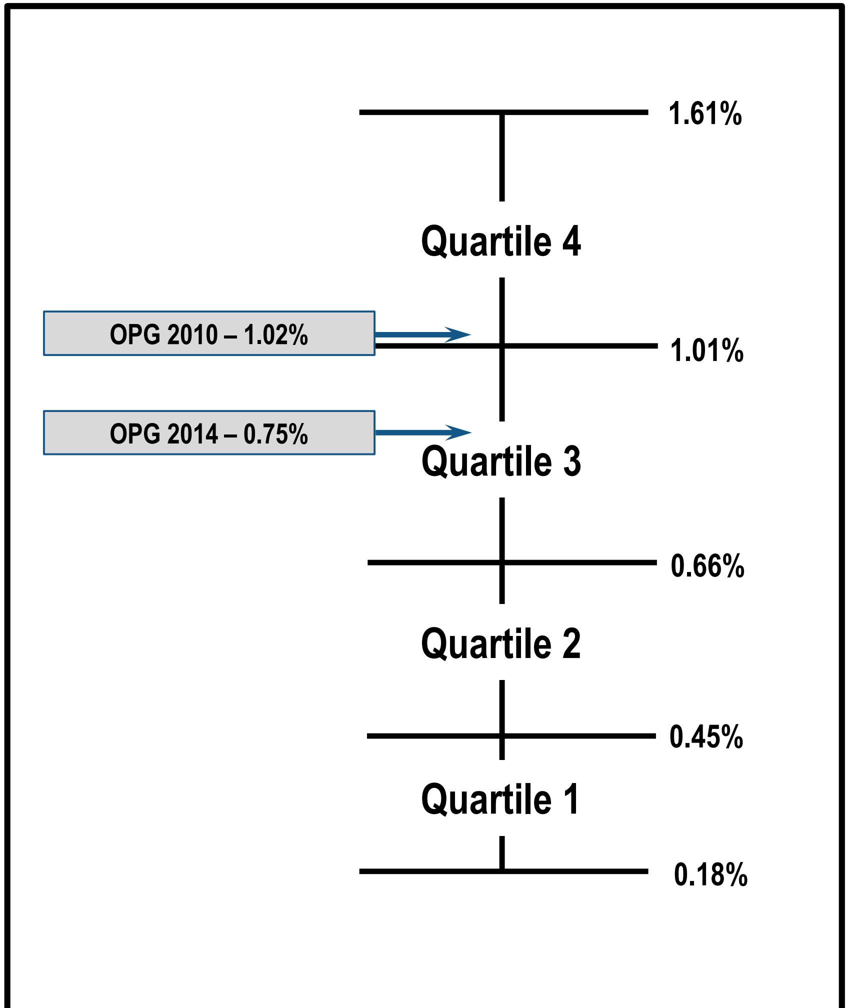
Benchmarking Study of OPG's Corporate Support Functions and Costs – Quartile Data

September 2016

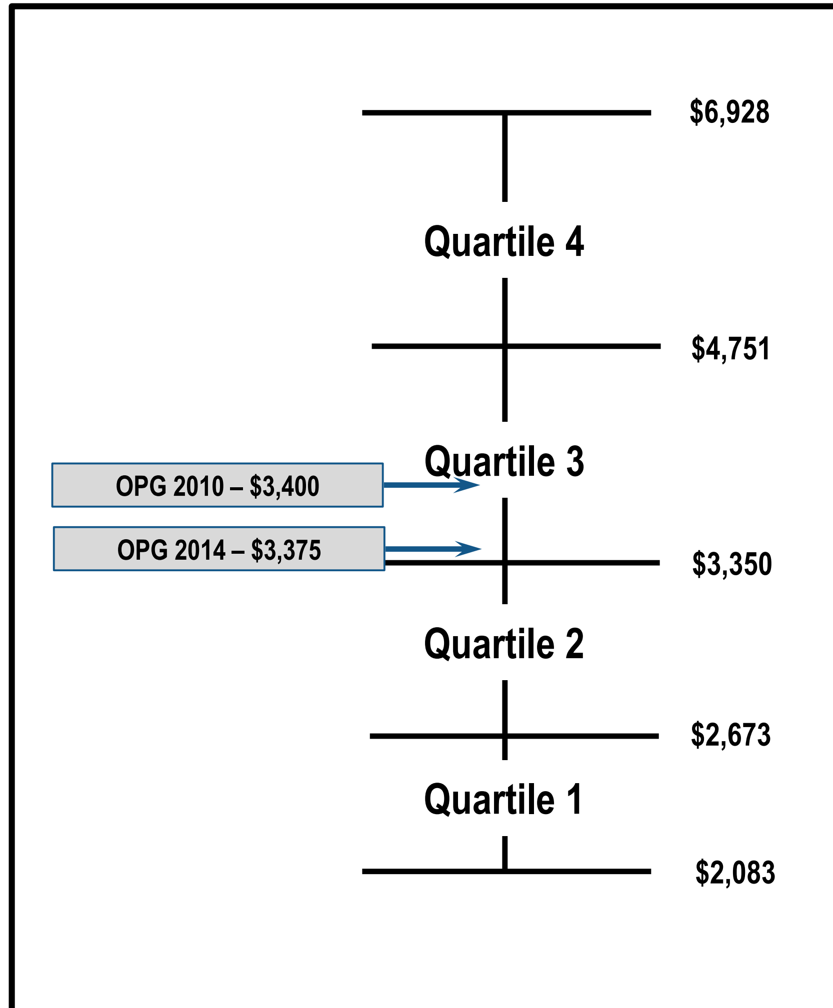
CONFIDENTIAL

Finance and HR Quartile Data

Finance Cost as a % of revenue

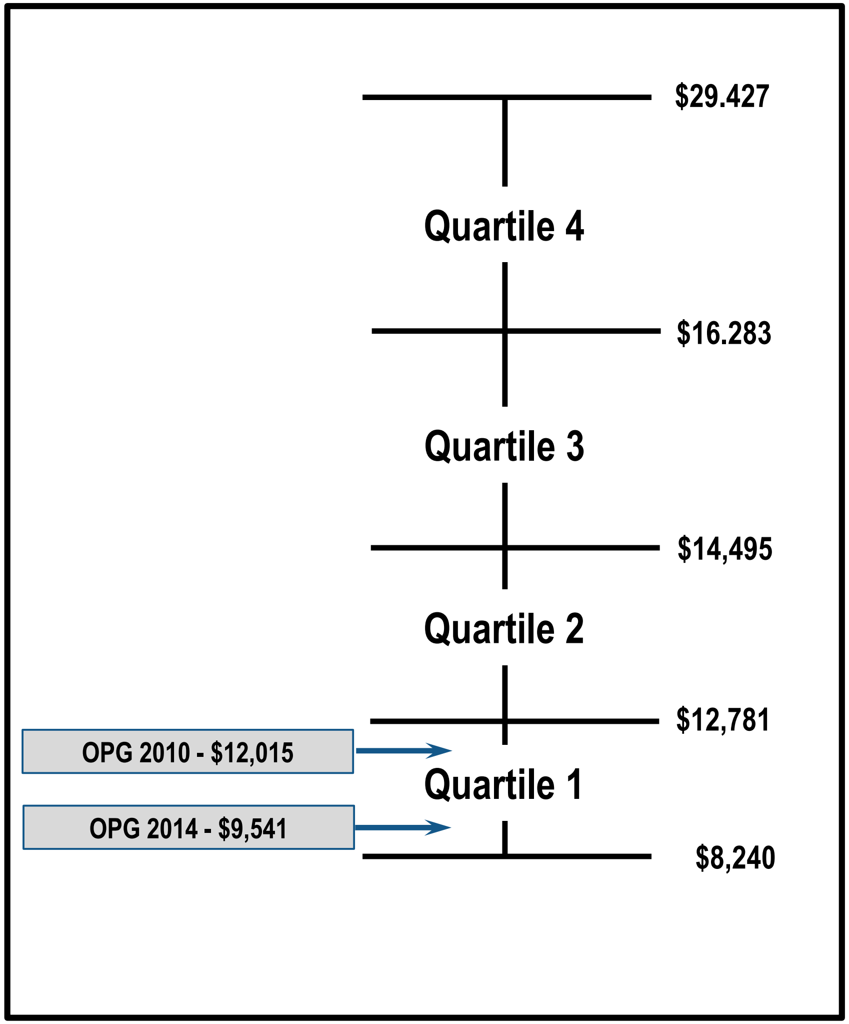


HR Cost per employee

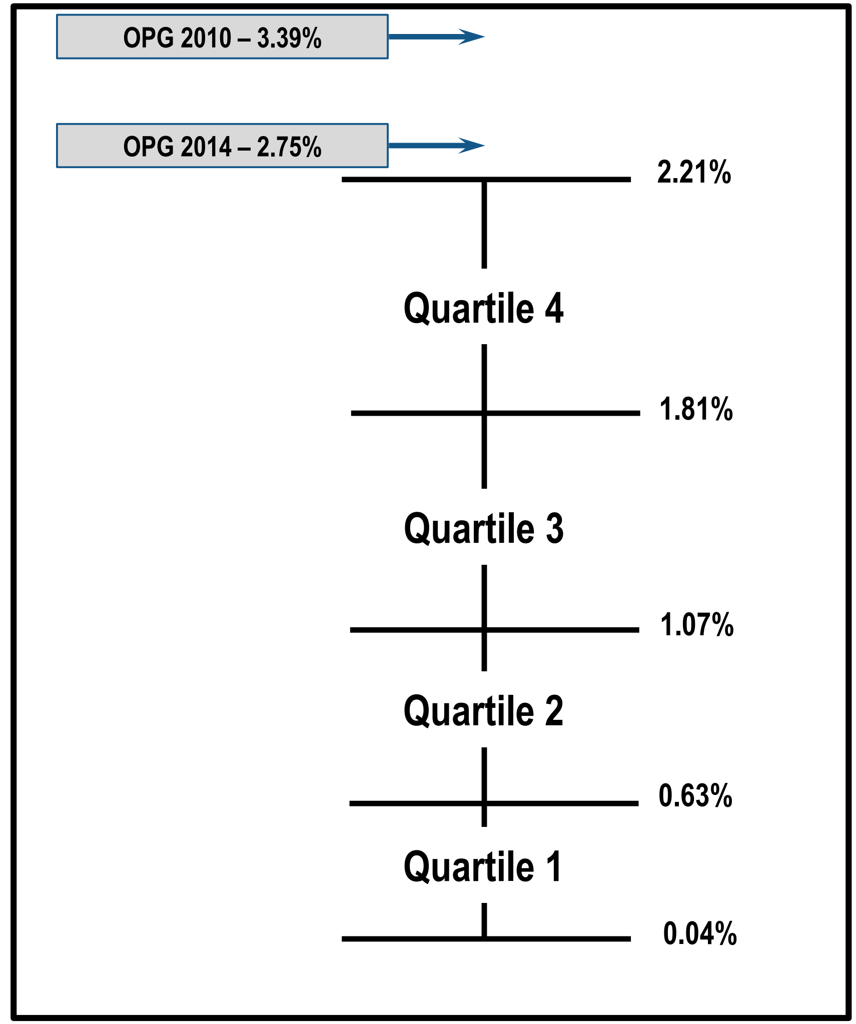


IT and ECS Quartile Data

IT Cost Per End User



ECS Cost as a % of revenue



The most significant challenges were faced in the ECS areas of Risk Management and Environmental, Health and Safety; Procurement; and, Real Estate and Facilities Management. These were the ECS areas where OPG's costs were most significant and where the gap between OPG and peers was greatest.

OPG's costs associated with Risk Management and Environmental, Health and Safety, and Procurement continue to be driven by nuclear-specific requirements and commitment to upholding OPG's social license to operate. OPG's adherence to strict CNSC regulations and its robust safety and environmental programs are examples of key cost drivers in these areas. OPG's nuclear stations have well-established environmental monitoring programs that are designed to assess impacts on human health and the environment, demonstrate compliance with regulatory limits, validate the effectiveness of containment and effluent controls, and verify predictions made by environmental risk assessments. For example, in addition to all of the conventional environmental requirements, OPG conducts a radiological environmental monitoring program to assess, among other things, radiation exposure to members of the public from OPG's nuclear generating stations. The Procurement function must address the significant quality requirements for materials that are used in nuclear facilities. In addition, the cost of Procurement activities is affected by aging assets, parts obsolescence and the limited market availability of nuclear qualified suppliers. The majority of the utilities included in OPG's peer benchmarking group were not nuclear power producers and therefore do not have the same breadth of requirements as OPG in these areas.

OPG's Real Estate and Facilities Management costs continue to be driven by business requirements associated with the large number of nuclear and hydroelectric facilities and the geographic spread of the facilities across the province. As noted in Attachment 1 (p. 16), OPG's Real Estate and Facilities Management costs included all facility costs

Management and Environmental, Health and Safety, Corporate Communications, Planning and Strategy, Executive Office and Procurement.

associated with its corporate regulated operations, including facility costs associated with IT, HR and Finance functions. Such facility costs were embedded in each particular function for OPG's peers. This limitation had an unfavourable impact on OPG's Real Estate and Facilities Management performance.

In addition, OPG's performance in relation to the peer benchmarks for each function is significantly influenced by its labour costs. This is also reflected in OPG's performance in the compensation benchmarking study carried out by Willis Towers Watson provided at Ex. F4-3-1 Attachment 2. As described in Ex. F4-3-1, OPG's regulated staff work in a predominantly unionized environment, with approximately 90 per cent of staff belonging to either the PWU or the Society. Given the extent of unionization, collective bargaining plays a dominant role in determining OPG's labour costs. Collective bargaining directly affects the wages and incentives provided to unionized employees, as well as the pensions and benefits they earn. Collective bargaining also has an indirect impact on the compensation provided to non-unionized positions because internal equity, career development and attracting experienced employees into management positions are important factors in workforce planning and development. As a result, OPG's performance in relation to the peer benchmarks in the Hackett study would be impacted to the extent that utilities in OPG's peer group are non-unionized and do not have the same collective bargaining requirements.

5.0 METHODS OF ALLOCATION

The cost allocation methodology is the same as was previously evaluated and accepted by the OEB in EB-2013-0321, EB-2010-0008 and EB-2007-0905. The cost allocation methodology uses two methods to distribute costs among the business units: direct assignment and allocation. In 2013, OPG's allocation methodology was also independently evaluated by HSG Group Inc and the report was filed to the OEB as part of EB-2013-0321 at Ex. F5-5-1.

Section VIII. Summary of Conclusions

OPG's cost allocation methodology for Centralized Services and Common Costs (including Asset Service Fees) distributes / charges those costs to Business Segments and to stations in a manner that meets current best practices and is consistent with cost allocation precedents established by the OEB. The responses provided by Service Recipients and Service Providers to the surveys, and the interviews conducted by HSG Group as well as other information reviewed, provide sufficient, reliable evidence that OPG's allocation of CSA costs meets the OEB's 3 prong test. The results of the allocation based on the 2014 year in the Business Plan 2013-15 are presented in Table 5.

Table 5: Results of Allocation for 2014 in Business Plan 2013-15 ($ millions)

Service Provider	Nuclear	Hydro-Regulated	Hydro Unregulated	Thermal	Other Business	Total
BAS - Outsourcing	$57.3	$2.7	$6.4	$3.2	$3.2	**$ 72.8**
BAS- Work Programs	33.3	3.4	7.7	5.2	3.0	**52.6**
BAS – Supply Chain	60.8	1.4	2.5	2.9	1.7	**69.3**
BAS - Real Estate	114.2	1.5	3.2	4.3	1.4	**124.6**
People & Culture	92.1	4.4	9.3	7.5	3.9	**117.2**
Finance	45.5	3.4	6.0	4.6	2.7	**62.2**
Corporate Centre	32.7	5.1	11.6	6.7	2.9	**59.0**
CO&E	17.9	8.0	6.4	5.8	3.9	**42.0**
CSA Groups	**453.8**	**29.9**	**53.1**	**40.2**	**22.7**	**599.7**
Hydro / OSL Common	3.8	7.6	56.5	8.5	0.2	**76.6**
Centrally held costs	358.1	21.1	49.1	49.0	2.4	**479.7**
Total	**$ 815.7**	**$ 58.6**	**$ 158.7**	**$ 97.7**	**$ 25.3**	**$1,156.0**

BAS = Business & Administrative Services; CO&E = Commercial Operations & Environment

OPG Peer Group

Composite Peer Group
Ameren Corporation
American Water
Areva SA
Arizona Public Service Company
Black Hills Corporation
CMS Energy Corporation
Constellation Energy Resources, LLC
Contour Global Ltd.
ENMAX Corporation
Florida Power & Light Company
Lower Colorado River Authority
National Grid plc
NiSource Inc
NorthWestern Corporation
Pepco Holdings, Inc.
Public Service Energy Group
RRI Energy, Inc
SaskPower
We Energies

Peer Group Nuclear Operators: Ameren Corp, Areva, Arizona Public Service Company, Constellation Energy Resources, Florida Power and Light, Public Service Energy Group

Nuclear SR&ED ITCs and Taxes

1) As Proposed by OPG

Tax Expense	Formula	Reference Document	2013	2014	2015	2016	Reference Document	2017	2018	2019	2020	2021	Total for Test Period
Regulatory Taxable Income Before Tax Loss Carry-Over		JT3.13 Tables 1-4	- 358.9	- 286.7	- 162.2	- 148.7	N1-1-1 Table 8	115.5	10.6	12.0	343.7	86.2	
Tax Loss Carry-Over			-	-	-	-		-	-	-	-	-	
Regulatory Taxable Income After Tax Loss Carry-Over	A		- 358.9	- 286.7	- 162.2	- 148.7		115.5	10.6	12.0	343.7	86.2	
Regulatory Federal Taxes	B = Ax15%		- 53.8	- 43.0	- 24.3	- 22.3	N1-1-1 Table 8	17.3	1.6	1.8	51.6	12.9	
Regulatory Provincial Taxes	C = Ax10%		- 35.9	- 28.7	- 16.2	- 14.9	N1-1-1 Table 8	11.6	1.1	1.2	34.4	8.6	
Taxes	D = B+C		- 89.7	- 71.7	- 40.6	- 37.2		28.9	2.7	3.0	86.0	21.5	
SR&ED ITCs Utilized per OPG	E	L6.10 Staff#188 Line 11	- 23.4	- 61.5	- 31.8	- 18.4		- 18.4	- 18.4	- 18.4	- 18.4	- 18.4	
Net Taxes Calculated per OPG	F = D-E		- 113.1	- 133.2	- 72.4	- 55.6	N1-1-1 Table 8	10.5	- 15.8	- 15.4	67.5	3.2	50.0

Note 1 - OPG assumes that all SR&ED ITCs earned is used in the year. Therefore, there is no SR&ED ITCs to carry forward.

2) Proposed by OEB Staff

Tax Expense	Formula	Reference Document	2013	2014	2015	2016	Reference Document	2017	2018	2019	2020	2021	Total for Test Period
Regulatory Taxable Income After Tax Loss Carry-Over	A		- 358.9	- 286.7	- 162.2	- 148.7	N2-1-1 Table 2	47.7	-	-	310.4	53.5	
Regulatory Federal Taxes	B = Ax15%		- 53.8	- 43.0	- 24.3	- 22.3	N2-1-1 Table 2	7.0	-	-	46.6	8.0	
Regulatory Provincial Taxes	C = Ax10%		- 35.9	- 28.7	- 16.2	- 14.9	N2-1-1 Table 2	4.7	-	-	31.0	5.4	
Taxes	D = B+C		- 89.7	- 71.7	- 40.6	- 37.2		11.7	-	-	77.6	13.4	
SR&ED ITCs Earned	E	L6.10 Staff#188 Line 1	- 35.5	- 33.0	- 19.3	- 18.7		- 18.4	- 18.4	- 18.4	- 18.4	- 18.4	
Net Taxes	F = D-E		-	-	-	-	N1-1-1 Table 8	- 6.7	- 18.4	- 18.4	59.2	- 5.0	10.7
			Note: No negative taxes as OPG did not receive any tax refund for SR&ED ITCS							Reduce by Carried Forward S&RED			71.0
											Net Taxes		- 60.30

SR&ED Continuity Schedule by OEB Staff	Formula	Reference Document	2013	2014	2015	2016
Earned in the Year	G	L6.10 Staff#188 Line 1	35.9	33.0	19.3	18.7
Carried Forward from Previous Year	H = K	L6.10 Staff#188 Line 2	8.1	-	33.0	52.3
Available for Use in the Year	I = G+H		44.0	33.0	52.3	71.0
Utilized Against Nuclear Tax Expense in the Year	J	Notes 2, 3	44.0	-	-	-
Remaining to be Carried Forward to the Next Year	K = I-J		-	33.0	52.3	71.0

Note 2 - SR&ED ITCs can only be used if there is tax expenses to use it against. There was no tax expense in 2014 to 2016 as per line D
Note 3 - Assume 2013 SR&ED ITCs all used in 2013 even though there was a tax loss in 2013 since 2013 SR&ED ITCs would have been dealt with in the 2014/2015 PA and not in the current proceeding. Therefore, assume no 2013 SR&ED ITCs carried forward in 2014.

Table 3
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2013-2016

Line No.	Particulars	Note	2013 Actual	2014 Actual	2015 Actual	2016 Budget
			(a)	(b)	(c)	(d)
	Determination of Regulatory Taxable Income					
1	**Regulatory Earnings Before Tax**	1	(56.7)	271.6	162.2	162.2
	Additions for Regulatory Tax Purposes:					
2	**Depreciation and Amortization**		319.1	395.8	437.6	458.3
3	**Nuclear Waste Management Expenses**		25.1	31.3	57.7	60.0
4	**Receipts from Nuclear Segregated Funds**		44.7	42.3	41.1	66.1
5	**Pension and OPEB Accrual**		305.3	384.8	439.6	437.9
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		62.9	41.9	49.5	165.3
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(18.7)	(12.4)	(4.5)	(8.9)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**		76.8	75.2	70.3	65.8
9	**Disallowance of Niagara Tunnel Project Expenditures**		0.0	77.2	2.1	(21.6)
10	**Taxable SR&ED Investment Tax Credits**		28.4	19.2	62.3	18.7
11	**Other**		20.2	39.4	61.1	61.8
12	**Total Additions**		863.8	1,094.7	1,216.8	1,303.3
	Deductions for Regulatory Tax Purposes:					
13	**CCA**	2,3	307.7	404.3	425.7	513.8
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		104.7	109.1	126.3	162.2
15	**Contributions to Nuclear Segregated Funds**		98.1	170.1	172.8	176.7
16	**Pension Plan Contributions**		242.9	322.5	331.3	326.6
17	**OPEB/SPP Payments**		81.9	97.0	108.3	111.3
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		50.9	55.0	0.4	12.0
19	**Deductible SR&ED Qualifying Expenditures**		130.9	174.8	40.3	28.5
20	**Other**		1.6	11.0	6.7	24.2
21	**Total Deductions**		1,018.7	1,343.7	1,211.7	1,355.3
22	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 12 - line 21)	4	(211.6)	22.7	167.3	110.2
23	**Tax Loss Carry-Over**	5	0.0	0.0	0.0	0.0
24	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 22 + line 23)		(211.6)	22.7	167.3	110.2
25	**Regulatory Income Taxes - Federal** (line 24 x line 29)		(31.7)	3.4	25.1	16.5
26	**Regulatory Income Taxes - Provincial** (line 24 x line 30)		(21.2)	2.3	16.7	11.0
27	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(23.6)	(61.7)	(31.9)	(18.8)
28	**Total Regulatory Income Taxes** (line 25 + line 26 + line 27)		(76.5)	(56.0)	9.9	8.7
	Income Tax Rate:					
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%

For notes see Table 3b.

Table 2
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)
(Updated Ex. F4-2-1 Table 3a)
Years Ending December 31, 2017-2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	143.7	134.7	142.7	391.1	361.6
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**	2	367.0	395.0	400.3	541.2	316.7
3	**Nuclear Waste Management Expenses**	3	63.9	63.2	77.9	66.5	68.8
4	**Receipts from Nuclear Segregated Funds**	4	84.4	85.7	120.4	152.0	193.7
5	**Pension and OPEB Accrual**	5	291.2	298.7	343.3	352.3	359.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		(24.0)	(24.0)	0.0	0.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(2.2)	(2.2)	0.0	0.0	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	25.9	22.1	18.3	14.5	12.4
9	**Taxable SR&ED Investment Tax Credits**		18.4	18.4	18.4	18.4	18.4
10	**Other**		63.7	49.2	38.4	38.6	40.2
11	**Total Additions**		888.4	906.2	1,016.9	1,183.4	1,009.3
	Deductions for Regulatory Tax Purposes:						
12	**CCA**	7	394.2	504.4	571.1	594.8	597.0
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	8	217.5	227.9	232.8	283.6	317.0
14	**Contributions to Nuclear Segregated Funds**	9	0.0	0.0	0.0	0.0	0.0
15	**Pension Plan Contributions**	10	200.0	202.9	243.5	247.9	250.6
16	**OPEB/SPP Payments**	10	91.1	95.7	99.9	104.3	108.5
17	**Deductible SR&ED Qualifying Expenditures**		27.7	27.7	27.7	27.7	27.7
18	**Other**		20.3	0.1	1.1	5.7	16.5
19	**Total Deductions**		950.9	1,058.8	1,176.0	1,264.1	1,317.4
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		81.1	(18.0)	(16.4)	310.4	53.5
21	**Tax Loss Carry-Over**		(34.4)	18.0	16.4	0.0	0.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		46.7	(0.0)	(0.0)	310.4	53.5
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		7.0	0.0	0.0	46.6	8.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		4.7	0.0	0.0	31.0	5.4
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(6.7)	(18.4)	(18.4)	59.2	(5.0)
	Income Tax Rate:						
27	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
29	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 2a.

Board Staff Interrogatory #185

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

Interrogatory

Reference:
Ref: Exh F4-2-1, page 1
OPG is seeking approval for nuclear income tax expense of ($18.4)M, ($18.4)M, ($18.4)M, $51.2M, and $51.7M from 2017 to 2021 respectively.

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

Response

As explained in Ex. L-6.10-1 Staff-187, the Scientific Research and Experimental Development Income Tax Credit ("SR&ED ITCs") reported in a given year's regulatory income tax calculation include the regulated portion of SR&ED ITCs utilized (or projected to be utilized) to reduce OPG's corporate income taxes payable for that year. The forecasted earned SR&ED ITCs of $18.4M for each of 2017 to 2019 are expected to be earned and utilized to reduce OPG's income taxes payable in those years, and therefore are reflected in the regulatory income tax calculations for those years.

Board Staff Interrogatory #186

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

Interrogatory

Reference:
Ref: Exh F4-2-1, page 2
ITCs for SR&ED expenditures are recognized in the calculation of regulatory income taxes.

a) Please indicate if there is any other ITCs OPG qualifies for.

b) If yes, please identify and quantify the ITCs.

c) Please indicate whether they are recognized in the calculation of regulatory income taxes. If they are not, please explain why not.

Response

(a)-(c) There are no other Investment Tax Credits (ITCs) for which OPG qualifies.

Board Staff Interrogatory #187

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

Interrogatory

Reference:
Ref: Exh F4-2-1, page 10, and Table 3

Per page 10, OPG can claim a non-refundable ITC for SR&ED. In Table 3, 2014 regulatory income taxes were ($56.0M) mainly as a result of a $61.7M SR&ED ITC.

a) Please confirm that OPG did not receive a refund for the $61.7M SR&ED ITC.

b) Please explain the treatment of the $61.7M SR&ED ITC and whether it was carried forward and applied to the calculation of regulatory income taxes in 2015 or future years.

Response

a) & b)

The $61.7M SR&ED ITC does not constitute a refund and has not been carried forward to future years as explained below.

SR&ED ITCs reported in a given year's regulatory income tax calculation are comprised of two items:

1) Regulated Portion of Utilized SR&ED ITCs: The regulated portion of SR&ED ITCs utilized to reduce OPG's actual corporate income taxes payable for the year, using a 75 percent recognition percentage for taxation years subject to audit. As discussed in Ex. F4-2-1, section 3.4, the 75 percent recognition factor is applied in accordance with generally accepted accounting principles and is based on an assessment of the likelihood of the credits ultimately being allowed. Amounts of SR&ED ITCs utilized in the year include SR&ED ITCs earned in the year as well as any amounts carried over to/from a different year in line with OPG's corporate income tax calculations.

2) Tax Audit Results: Upon resolution of a prior year income tax audit, the regulated portion of the difference between the final amount of actual SR&ED ITCs allowed for that year and the amount previously recognized (i.e. at 75 percent).

The breakdown of the $61.7M is detailed in Ex. L-6.10-1 Staff-188, Attachment 1, Table 1, col. (b). It shows that the recognized portion of utilized SD&ED ITCs was $50.0M for nuclear and $0.2M for regulated hydroelectric, with the remaining $11.5M on account of income tax audit results.

OPG notes that, of the $61.7M, approximately $12M was recorded as a ratepayer credit in the Income and Other Taxes Variance Account in 2014 upon resolution of prior taxation year audits.[1] Other variances between actual reported and forecast SR&ED ITCs, which predominantly relate to differences between actual and forecast levels of underlying qualifying expenditures, are not within the scope of the Income and Other Taxes Variance Account, and the associated forecast risk is borne by the shareholder.

[1] The credit entry into the Income and Other Taxes Variance Account is explained at EB-2014-0370 Ex. H1-1-1, p. 8, lines 19-22 and p. 9, lines 5-10, and EB-2014-0370 Ex. H1-1-2, section 3.6. The credit entry is shown as $9.0M at EB-2014-0370 Ex. H1-1-2, Table 6, line 17, col. (l), which is net of taxes payable on the ITCs.

Board Staff Interrogatory #188

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

Interrogatory

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

a) The 2015 Nuclear SR&ED ITC included in the EB-2013-0321 Payment Amount Order is $9.4M as seen in Table 2a. Please confirm that there will be no true up to the actual 2015 SR&ED ITC of $31.9M (i.e. it will not be included in the Income and Other Taxes Variance Account).

b) Please provide a continuity schedule of the SR&ED credits available, used against regulatory income tax, carried forward or back from 2013 to 2021.

Response

a) Confirmed.

Exhibit L-6.10-1 Staff-187 explains the two items reported as the SR&ED ITC amount in a given year's regulatory income tax calculation. The regulated portion of utilized SR&ED ITCs of $26.0M for nuclear and $0.1M for regulated hydroelectric and $5.8M related to income tax audits comprise the $31.9M SR&ED ITC amount for 2015, as detailed in Attachment 1, Table 1, col. (c). Of the $31.9M, approximately $5M was recorded as a ratepayer credit in the Income and Other Taxes Variance Account in 2015 upon resolution of a prior year taxation year audit.[1] No other variances between the $31.9M amount and the 2015 OEB-approved amount of $9.4M have or are expected to be recorded in the Income and Other Taxes Variance Account, as these variances relate to differences between actual and forecast underlying qualifying expenditure levels. Such variances are not within the scope of the Income and Other Taxes Variance Account and are borne by (or accrue to) the shareholder.

b) Attachment 1 provides a 2013-2021 continuity schedule of SR&ED ITCs attributed to the regulated business and reported in the regulatory income tax calculations in the pre-filed evidence.

[1] The credit entry into the Income and Other Taxes Variance Account is explained at Ex. H1-1-1, p. 12, lines 17-24 and is shown as $4.2M at Ex. H1-1-1, Table 6, line 13, col. (c), which is net of taxes payable on the ITCs.

Numbers may not add due to rounding.

Table 1
Continuity Schedule of Scientific Research & Experimental Development Investment Tax Credits (SR&ED ITCs) ($M)

Line No.	Particulars	Actual 2013	Actual 2014	Actual 2015	Budget 2016	Plan 2017	Plan 2018	Plan 2019	Plan 2020	Plan 2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Nuclear:									
	Amounts Utilized for OPG's Corporate Income Tax Purposes [1]									
1	Earned in the Year	35.5	33.0	19.3	18.7	18.4	18.4	18.4	18.4	18.4
2	2012 ITCs Brought Forward and Other Adjustments	8.1	-	-	-	-	-	-	-	-
3	2013 ITCs (Carried Forward) / Brought Forward	(23.7)	23.7	-	-	-	-	-	-	-
4	2014 ITCs (Carried Forward) / Brought Forward	-	(6.8)	6.8	-	-	-	-	-	-
5	Total Amount Utilized for Corproate Income Tax Purposes	19.8	50.0	26.0	18.7	18.4	18.4	18.4	18.4	18.4
	Previously Unrecognized Amounts Recognized upon Resolution of Tax Audit									
6	2008 Tax Audit (for April to December)	3.5	-	-						
7	2009 Tax Audit	-	5.7	-						
8	2010 Tax Audit	-	5.9	-						
9	2011 Tax Audit	-	-	5.8						
10	Total Amount Related to Prior Year Income Tax Audits	3.5	11.5	5.8	-	-	-	-	-	-
11	**Total Nuclear SR&ED ITCs Reported in Regulatory Income Taxes**	**23.4**	**61.5**	**31.8**	**18.7**	**18.4**	**18.4**	**18.4**	**18.4**	**18.4**
	Regulated Hydroelectric:									
	Amounts Utilized for OPG's Corporate Income Tax Purposes [1]									
12	Earned in the Year	0.1	0.1	0.1	0.1					
13	2012 ITCs Brought Forward and Other Adjustments	0.1	-	-	-					
14	2013 ITCs (Carried Forward) / Brought Forward	(0.1)	0.1	-	-					
15	2014 ITCs (Carried Forward) / Brought Forward	-	0.0	0.0	-					
16	Total Amount Utilized for Corproate Income Tax Purposes	0.2	0.2	0.1	0.1					
	Previously Unrecognized Amounts Recognized upon Resolution of Tax Audit									
17	2008 Tax Audit (for April to December)	0.1	-							
18	2009 Tax Audit	-	0.0	-	-					
19	2010 Tax Audit	-	0.0	-	-					
20	2011 Tax Audit	-	-	0.0	-					
21	Total Amount Related to Prior Year Income Tax Audits	0.1	0.0	0.0	-					
22	**Total Regulated Hydro SR&ED ITCs Reported in Regulatory Income Taxes**	**0.2**	**0.2**	**0.1**	**0.1**					
23	**Total SR&ED ITCs Reported at Ex. F4-2-1 Table 3 Line 27**	**23.6**	**61.7**	**31.9**	**18.8**					
24	**Total SR&ED ITCs Reported at Ex. F4-2-1 Table 3 Line 25**					**18.4**	**18.4**	**18.4**	**18.4**	**18.4**

Note:
1 Amounts are presented at 75% to reflect percentage of recognition in accordance with generally accepted accounting principles

here.

MR. SMITH: This is what was left here. Oh, okay.

MR. SHEPHERD: Are there copies of this compendium?

MR. MILLAR: All of these documents are on the record, and they can be pulled up on the screen, and we have a couple of extras.

MR. MUKHERJI: I will make one for you.

MR. SHEPHERD: Thank you. You are going to file them on the website anyway, right?

MR. MILLAR: Yes, but they are just interrogatory responses. They are just copies of the responses.

MS. KWAN: Okay, does everyone have one?

MR. SHEPHERD: That's fine, go ahead.

MS. KWAN: Okay. So my first question is going to be on depreciation on issue 6.9. It's Staff 178, which is page 1 of the compendium.

So Pickering depreciation is based on an end of life of December 31st, 2020. Can you provide the depreciation expense if OPG was able to extend the Pickering operations to the 2022 and 2024?

MR. KOGAN: The challenge with that question is that the depreciation expense includes depreciation of asset retirement costs, which are a function of the nuclear liabilities. The nuclear liabilities right now are based on also an end-of-2020 date. We have not calculated what the adjustment would be for these liabilities at the time that the high confidence is reached, and therefore can't calculate depreciation on a number I effectively don't have, because the asset base will change through asset retirement costs.

MS. KWAN: Okay. So you don't think you will be able to do that calculation right now then, or even as a part of an undertaking?

MR. KOGAN: I think that we responded to this in GEC... I think it's in GEC 57 or 59, if memory serves, where we discussed that right now because we are still operating under the existing ONFA reference plan that it wouldn't be helpful or very meaningful to calculate that number, because that number would be different once the new cost estimates are in effect, plus there is uncertainty with respect to other inputs into that calculation, such as the specific timing, in terms of when the change in liabilities would be affected on account of high confidence for Pickering, as well as possibly discount rate.

MS. KWAN: Okay, so my next question is going to be on issue 6.10 for taxes. And I am going to refer you to page 4 of the compendium, which is Staff 187.

So in this response it says that SR&ED ITCs are utilized to reduce OPG's actual corporate income taxes payable for the year, and then in the next IR, Staff 188, which is page 6 of the compendium, in table 1 it show a continuity schedule of the SR&ED ITCs, and just using 2013 as an example, 2013 total SR&ED ITCs is 23.6-million.

And then if I go to page 8 on the -- of the compendium, which is Exhibit F4, tab 2, schedule 1, table 3, the sum of the 2013 regulatory federal and provincial income taxes is negative 52.9. And table 3 also shows that 23.6 million of the SR&ED ITC is being utilized.

So my question is how can the SR&ED ITCs be utilized when there is no taxes payable for that year since there was a tax loss of 52.9 million?

MR. KOGAN: So as we note in Staff 185, the amount in your example of 23.6 represents the regulated portion of the SR&ED ITCs utilized to reduce OPG's corporate income taxes payable.

MS. KWAN: So you are saying it's not just the nuclear portion? Is that what -- or is there any amount that's being carried back?

MR. KOGAN: I am saying that's right, it's more than nuclear. It represents the amounts that we actually apply based on our corporate tax returns.

MS. KWAN: Okay. So the table 1, okay -- so the table 3 on page 8, that's for the total prescribed facilities. But would you be able to provide that just for the nuclear facilities?

MR. KOGAN: So your question is to break out table 3 between nuclear and prescribed nuclear and prescribed hydroelectric facilities; is that the question?

MS. KWAN: Yes.

MR. KOGAN: We will undertake to do that.

MR. MILLAR: JT3.13.

UNDERTAKING NO. JT3.13: TO BREAK OUT EXHIBIT F4, TAB 2, SCHEDULE 1, TABLE 3 BETWEEN NUCLEAR AND PRESCRIBED NUCLEAR AND PRESCRIBED HYDROELECTRIC FACILITIES

UNDERTAKING JT3.13

Undertaking

TO BREAK OUT EXHIBIT F4, TAB 2, SCHEDULE 1, TABLE 3 BETWEEN PRESCRIBED NUCLEAR AND PRESCRIBED HYDROELECTRIC FACILITIES

Response

Regulatory income taxes for the historical and bridge periods are calculated as described at Ex. F4-2-1, p. 2, lines 13-18:

> *As in EB-2013-0321, regulatory income taxes for the historical and bridge periods continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, less SR&ED ITCs. Total regulatory income taxes are then allocated based on each business' regulatory taxable income, while SR&ED ITCs are predominantly directly attributed to each business unit based on the underlying expenditures giving rise to the ITCs.*

As this undertaking arose in the context of OEB Staff's questions on interrogatories related to historical years, in line with the above, Attachment 1 provides a break out of regulatory taxable income between prescribed nuclear and prescribed hydroelectric businesses for each of the years 2013-2016 that was used to allocate total regulatory income taxes (before SR&ED ITCs) calculated at Ex. F4-2-1 Table 3a, lines 25 and 26. This allocation is proportionate, unless there is negative taxable income for one of the two businesses in a given year. In that situation, consistent with the evidence in EB-2013-0321 Ex. F4-2-1, p. 3, lines 11-16, the negative taxable income of one of the regulated businesses reduces or eliminates the tax expense of the other regulated business.[1]

SR&ED ITCs continue to be reported as a component of regulatory income tax expense for each of the regulated businesses based on underlying qualifying expenditures that gave rise to the ITCs, irrespective of each business' regulatory taxable income. As explained in Ex. L-6.10-1 Staff-187, these SR&ED ITC amounts represent each regulated business' portion of the total SR&ED ITCs utilized to reduce OPG's overall corporate income taxes payable for the year (subject to a 75 percent recognition percentage for taxation years subject to audit).

Chart 1 below shows the components of regulatory income taxes for the two regulated businesses for each of the years 2013-2016. The combined regulatory income tax expense for the prescribed facilities in Chart 1 is as calculated at Ex. F4-2-1 Table 3a, line 28. Each year's total regulatory income taxes for the nuclear business is as shown in Ex. F4-2-1 Table 2, line 1.

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[1] Any remaining negative taxable income (i.e. a regulatory tax loss) is reported as negative income tax expense for the year, as illustrated for the 2013 year. The OEB applied the 2013 regulatory tax loss as a carry forward to reduce the 2014 regulatory income tax expense, as reflected in the EB-2013-0321 Payment Amounts Order, Appendix A, Table 7, line 22 and Table 7a, footnote 5.

Chart 1

$M	Nuclear Facilities	Hydroelectric Facilities	Total
	2013		
Income Taxes before SR&ED ITC	(52.9)	-	(52.9)
SR&ED ITC	(23.5)	(0.1)	(23.6)
Total Regulatory Income Taxes	(76.4)	(0.1)	(76.5)
	2014		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	5.7	5.7
SR&ED ITC	(61.5)	(0.2)	(61.7)
Total Regulatory Income Taxes	(61.5)	5.5	(56.0)
	2015		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	41.8	41.8
SR&ED ITC	(31.8)	(0.1)	(31.9)
Total Regulatory Income Taxes	(31.8)	41.7	9.9
	2016		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	27.5	27.5
SR&ED ITC	(18.7)	(0.1)	(18.8)
Total Regulatory Income Taxes	(18.7)	27.4	8.7

Table 8
Updated Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)
(Updated Ex. F4-2-1 Table 3a)
Years Ending December 31, 2017 to 2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	171.2	152.5	160.5	413.7	383.6
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**	2	373.9	405.7	411.0	551.9	327.3
3	**Nuclear Waste Management Expenses**	3	63.9	63.2	77.9	66.5	68.8
4	**Receipts from Nuclear Segregated Funds**	4	84.4	85.7	120.4	152.0	193.7
5	**Pension and OPEB Accrual**	5	291.2	298.7	343.3	352.3	359.2
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		(24.0)	(24.0)	0.0	0.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(2.2)	(2.2)	0.0	0.0	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	6	25.9	22.1	18.3	14.5	12.4
9	**Taxable SR&ED Investment Tax Credits**		18.4	18.4	18.4	18.4	18.4
10	**Other**		63.7	49.2	38.4	38.6	40.2
11	**Total Additions**		895.2	916.9	1,027.6	1,194.1	1,019.9
	Deductions for Regulatory Tax Purposes:						
12	**CCA**	7	394.2	504.4	571.1	594.8	597.0
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	8	217.5	227.9	232.8	283.6	317.0
14	**Contributions to Nuclear Segregated Funds**	9	0.0	0.0	0.0	0.0	0.0
15	**Pension Plan Contributions**	10	200.0	202.9	243.5	247.9	250.6
16	**OPEB/SPP Payments**	10	91.1	95.7	99.9	104.3	108.5
17	**Deductible SR&ED Qualifying Expenditures**		27.7	27.7	27.7	27.7	27.7
18	**Other**		20.3	0.1	1.1	5.7	16.5
19	**Total Deductions**		950.9	1,058.8	1,176.0	1,264.1	1,317.4
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		115.5	10.6	12.0	343.7	86.2
21	**Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		115.5	10.6	12.0	343.7	86.2
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		17.3	1.6	1.8	51.6	12.9
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		11.6	1.1	1.2	34.4	8.6
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		10.5	(15.8)	(15.4)	67.5	3.2
	Income Tax Rate:						
27	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
29	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

See Ex. N1-1-1 Table 8a for notes

Numbers may not add due to rounding.

Table 2
Updated Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
(Updated Ex. C2-1-1 Table 1)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note or Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	PRESCRIBED FACILITIES						
1	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 3	77.3	77.3	77.3	77.3	7.9
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 3	51.4	53.1	65.7	52.5	52.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 3	12.5	10.1	12.2	14.0	15.9
	Return on ARC in Rate Base:						
4	**Return on Rate Base at Weighted Average Accretion Rate**	Note 1	25.9	22.1	18.3	14.5	12.4
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		167.1	162.6	173.4	158.2	89.1
7	**Income Tax Impact**	Note 2	55.7	54.2	57.8	52.7	29.7
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		222.8	216.8	231.2	211.0	118.8
	BRUCE FACILITIES						
9	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 4	68.6	68.6	68.6	68.6	68.6
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 4	71.0	68.1	73.0	78.6	63.5
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 4	2.7	3.2	3.0	3.6	5.0
12	**Accretion Expense**	Ex. N1-1-1 Table 4	462.1	473.2	489.1	505.6	523.4
13	**Less: Segregated Fund Earnings (Losses)**	Ex. N1-1-1 Table 4	395.8	412.5	429.5	446.1	462.3
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		156.4	150.4	153.1	157.7	148.6
16	**Income Tax Impact** (line 15 x tax rate / (1-tax rate))	Note 4	52.1	50.1	51.0	52.6	49.5
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		208.6	200.5	204.1	210.3	198.1
18	**Total Revenue Requirement Impact - Prescribed and Bruce Facilities**		431.4	417.3	435.4	421.2	316.9
	(line 8 + line 17)						

See Ex. N1-1-1 Table 2a for notes

Table 3
Prescribed Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 2)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		9,246.3				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		9,010.6	9,347.5	9,677.7	10,033.6	10,342.6
5	**Used Fuel Storage and Disposal Variable Expenses**	3	51.4	53.1	65.7	52.5	52.9
6	**Low & Intermediate Level Waste Management Variable Expenses**	4	12.5	10.1	12.2	14.0	15.9
7	**Accretion Expense**		490.5	495.0	510.8	526.1	541.6
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(217.5)	(227.9)	(232.8)	(283.6)	(317.0)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		9,347.5	9,677.7	10,033.6	10,342.6	10,636.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		9,179.0	9,512.6	9,855.7	10,188.1	10,489.3
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		8,240.1	8,577.8	8,931.7	9,268.2	9,589.6
13	**Earnings (Losses)**		422.2	439.6	456.9	473.4	488.9
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(84.4)	(85.7)	(120.4)	(152.0)	(193.7)
16	**Closing Balance** (lines 12 through 15)		8,577.8	8,931.7	9,268.2	9,589.6	9,884.9
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		8,409.0	8,754.8	9,099.9	9,428.9	9,737.2
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)						
18	**Opening Balance** (line 4 - line 12)		770.5	769.6	746.0	765.4	752.9
19	**Closing Balance** (line 10 - line 16)		769.6	746.0	765.4	752.9	751.2
20	**Average Unfunded Nuclear Liability Balance** ((line 18 + line 19)/2)		770.1	757.8	755.7	759.2	752.1
	ASSET RETIREMENT COSTS (ARC)						
21	**2016 Projected Closing Balance Before Year-End Adjustments**		800.5				
22	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
23	**Opening Balance** (col. (a): line 21 + line 22)		562.6	485.4	408.1	330.8	253.5
24	**Depreciation Expense**		(77.3)	(77.3)	(77.3)	(77.3)	(7.9)
25	**Closing Balance Before Year-End Adjustments** (line 23 + line 24)		485.4	408.1	330.8	253.5	245.6
26	**Average Asset Retirement Costs** ((line 23 + line 25)/2)		524.0	446.7	369.5	292.2	249.6
27	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 20 or line 26)		524.0	446.7	369.5	292.2	249.6

Notes:
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the 2017 Approved ONFA Reference Plan.
2 Adjustment expected to be recorded on December 31, 2016 associated with the change to the previous cost estimates related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences. Although these facilities were not included in the 2012 ONFA Reference Plan (see Ex. C2-1-1 Table 2, Note 6), they are included in the 2017 ONFA Reference Plan. As a result, the ARO is projected to increase by $4.4M at December 31, 2016, of which $2.2M is attributed to the prescribed facilities and $2.2M to the Bruce facilities. In accordance with GAAP, this amount will be expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility that is not used to support OPG's current operations.
3 See Ex. C2-1-1 Table 2, Note 3.
4 See Ex. C2-1-1 Table 2, Note 4.

Table 4
Bruce Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 3)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		11,373.1				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		10,083.5	10,462.3	10,842.5	11,209.0	11,595.8
5	**Used Fuel Storage and Disposal Variable Expenses**		71.0	68.1	73.0	78.6	63.5
6	**Low & Intermediate Level Waste Management Variable Expenses**		2.7	3.2	3.0	3.6	5.0
7	**Accretion Expense**		462.1	473.2	489.1	505.6	523.4
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(157.0)	(164.2)	(198.6)	(201.0)	(215.7)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		10,462.3	10,842.5	11,209.0	11,595.8	11,972.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		10,272.9	10,652.4	11,025.8	11,402.4	11,783.9
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		7,720.1	8,045.3	8,386.9	8,722.7	9,049.2
13	**Earnings (Losses)**		395.8	412.5	429.5	446.1	462.3
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(70.5)	(70.9)	(93.7)	(119.7)	(144.3)
16	**Closing Balance** (line 12 through 15)		8,045.3	8,386.9	8,722.7	9,049.2	9,367.1
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		7,882.7	8,216.1	8,554.8	8,885.9	9,208.1
	ASSET RETIREMENT COSTS (ARC)						
18	**2016 Projected Closing Balance Before Year-End Adjustments**		4,290.7				
19	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
20	**Opening Balance** (col. (a): line 18 + line 19)		2,999.0	2,930.4	2,861.9	2,793.3	2,724.8
21	**Depreciation Expense**		(68.6)	(68.6)	(68.6)	(68.6)	(68.6)
22	**Closing Balance** (line 20 + line 21)		2,930.4	2,861.9	2,793.3	2,724.8	2,656.2
23	**Average Asset Retirement Costs** ((line 20 + line 22)/2))		2,964.7	2,896.1	2,827.6	2,759.0	2,690.5

Notes
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the Approved 2017 ONFA Reference Plan
2 See Ex. N1-1-1 Table 3, Note 2.

was established to fund the lifecycle costs of long-term nuclear used fuel management.[7] Being a funding mechanism, ONFA does not have attribution of nuclear liabilities costs to appropriate periods over the station's productive life as one of its objectives. The ONFA was executed in 2003, but includes calculations and contributions effective as of OPG's inception in 1999.

The costs for used fuel management and L&ILW storage costs incurred during the stations' operating lives are not funded under the ONFA and cannot be drawn from the segregated funds. As these costs, referred to as "internally funded", are part of OPG's legal obligation for nuclear waste, they are included in the ARO and are funded from OPG's operating cash flow.

OPG's station-level quarterly contributions to the segregated funds are determined periodically, with reference to the funding liabilities contained in an approved ONFA reference plan in effect and corresponding segregated fund balances at a point in time. Prescribed funding formulae and rules set out in the ONFA are applied to calculate the contribution amounts based on the difference between the funding liabilities and fund balances. The discount rate used to calculate the funding liabilities is determined in accordance with the ONFA. ONFA reference plans, including all underlying cost estimates and assumptions, are required to be updated every five years or whenever there is a significant change as determined under the ONFA. Station-level continuities of the funding liabilities and segregated fund balances are maintained in accordance with the ONFA. The funded status of the funds at any point in time represents the difference between the funding obligations per an approved ONFA reference plan then in effect and the value of the segregated funds.

Cost estimates and underlying operational, economic and other planning assumptions reflected in the ONFA funding liabilities are determined through a comprehensive process that draws from a variety of sources, including the use of independent third party experts in

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[7] Refer to Ex. C2-1-1, p. 5, footnote 1 for the specific definition of the funding boundaries for each of the segregated funds.

different fields. Cost estimates and underlying assumptions are reviewed by the Province and their technical consultants prior to approval of ONFA reference plans. In addition to the funding liabilities for ONFA-funded costs, an approved ONFA reference plan contains cost estimates for internally funded costs, which are also subject to review by the Province.

The ONFA contains several specific features designed to reduce risk for future generations of Ontarians, by ensuring that sufficient funds are available to pay for nuclear liabilities. First, the segregated funds are held in third-party custodial accounts, externally administered and subject to extensive reporting controls. Second, OPG cannot withdraw monies from the funds, unless the withdrawal reimburses OPG for an eligible incurred expenditure related to nuclear waste management and decommissioning activities as specifically defined by the ONFA. These disbursements are subject to a detailed review and approval process by the Province. OPG does not have other rights to withdraw the funds, including on the agreement's termination, as discussed below. Third, as also discussed below, specific funding formulae and rules contained in the ONFA have been structured such that OPG has been required to fund a substantial portion of the underlying used fuel liabilities in earlier years, effectively as a form of funding conservatism.

Table 5
Projected Impact of 2017 ONFA Reference Plan Adjustment - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)
(Updated Ex. C2-1-1 Table 4)

Line No.	Description	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2016 Projected:								
1	**Decommissioning Program**	229.3	277.7	71.2	578.2	(52.6)	(40.5)	(93.1)	485.1
2	**Low and Intermediate Level Waste Storage Program**	15.0	43.5	35.5	94.0	26.7	(2.6)	24.2	118.2
3	**Low and Intermediate Level Waste Disposal Program**	(1.2)	33.1	26.5	58.4	(29.4)	(46.4)	(75.8)	(17.4)
4	**Used Fuel Disposal Program**	(193.7)	(245.4)	(431.8)	(871.0)	(440.3)	(617.0)	(1,057.2)	(1,928.2)
5	**Used Fuel Storage Program**	(9.7)	2.5	(90.4)	(97.6)	(42.3)	(47.5)	(89.8)	(187.4)
6	**ARO Adjustment Assignment to Station Level**	39.7	111.5	(389.1)	(237.9)	(537.7)	(754.0)	(1,291.8)	(1,529.7)
7	**Asset Retirement Cost Adjustment**	39.7	111.5	(389.1)	(237.9)	(537.7)	(754.0)	(1,291.8)	(1,529.7)

Notes:

1 Excludes ARO adjustment of $4.4M expected to be recorded on December 31, 2016 associated with the change to the previous cost estimates related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences. These facilities were not included in the 2012 ONFA Reference Plan but are included in the 2017 ONFA Reference Plan. See Ex. N1-1-1 Table 3, Note 2 for further details.

Board Staff Interrogatory #170

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

Interrogatory

Reference:
Ref: Exh F3-1-1 page 14

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

a) Are some of the groups within ECS included in those that were not benchmarked in the Towers report at Exh F4-3-1 Attachment 2?

b) Are some of the groups within ECS included in those that were not benchmarked in the Goodnight report at Exh F2-1-1 Attachment 4?

c) ECS cost in 2010 and 2014 is provided as a % of revenue. Please provide the ECS costs in dollars for 2010 and 2014.

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

Response

a) No, all of the groups within ECS were included in the Towers report at Ex. F4-3-1, Attachment 2.

b) Yes, some of the groups within ECS are included in those that were not benchmarked in the Goodnight report at Ex. F2-1-1, Attachment 2. For example, Corporate Support not directly supporting the Nuclear Program, such as the Law Division and Enterprise Risk Management, was excluded from the Goodnight report. The inclusion of these groups within ECS is consistent with the Hackett group benchmark methodology (Ex. F3-1-1, Attachment 1, p. 6); and similarly, the exclusion of these groups is consistent with Goodnight Consulting benchmarking methodology (Ex. F2-1-1, Attachment 2, p. 14). The difference in methodology is expected, as the Hackett Group and Goodnight benchmarking were performed for different objectives (see Ex. F3-1-1, Attachment 1, p. 5 and Ex. F2-1-1, Attachment 2, p. 3, respectively). Furthermore, each methodology ensures OPG is compared to peers on an apples to apples basis.

c) The ECS costs for OPG's regulated operations in dollars for 2010 and 2014 can be found at Ex. F3-1-1, Attachment 1, p. 11.

d) Referring to the 2014 ECS cost at Ex. F3-1-1, Attachment 1, p. 11 and forecasted corporate costs in Ex. F3-1-1, OPG has completed a high level estimate of the ECS costs allocated to nuclear business for 2017-2021: $99M in 2017; $99M in 2018; $99M in 2019; $99M in 2020; and $100M in 2021.

As in L-06.6-1 Staff-169, it should be further noted that these values represent an estimate based on information available to OPG. The values above have not been derived using the Hackett Group's taxonomy applied to 2010 and 2014 costs, or otherwise vigorously vetted by a similar taxonomy, as this is not an exercise OPG performs in its normal course of business. Furthermore, although ECS cost as a percentage of revenue was higher than peer in the Hackett Study, driven by OPG specific requirements (see Ex. F3-1-1, p. 15, lines 7-24), OPG HR cost per employee was comparable to peer and OPG IT cost per end user was better than peer (Ex. F3-1-1, p.14, lines 14-17).

3.0 NUCLEAR BUSINESS CASE SUMMARY INDEX

Tab No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date
		ONGOING PROJECTS FROM EB-2013-0321	
1	25619	Darlington Operations Support Building Refurbishment	Aug-15
2	31412	Darlington Class II Uninterruptible Power Supplies Replacement	Sep-15
3	31508 49158 49299*	Darlington Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment	May-15
4	31717	Darlington Improve Maintenance Facilities	Mar-12
5	33621	Darlington Secondary Control Area Air Conditioning Unit Replacement	Aug-15
6	33631	Darlington Chiller Replacement to Reduce CFC Emissions	Sep-10
7	33819	Darlington Major Pump-sets Vibration Monitoring System Upgrades	Oct-15
8	33955	Darlington Shutdown System Computer Aging Management	Feb-15
9	33973	Darlington Standby Generator Controls Replacement	May-15
10	33977	Darlington Digital Control Computer Replacement / Refurbishment / Upgrades	Jun-13
11	34000	Darlington Auxiliary Heating System	Jul-15
12	36001	Darlington Primary Heat Transport Pump Motor Capital Spares	May-13
13	41023 49247	Pickering Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure	Sep-14
14	46634	Pickering A Fuel Handling Single Point of Vulnerability Equipment Reliability Improvement	May-12
		COMPLETED/DEFERRED/CANCELLED PROJECTS FROM EB-2013-0321	
15	49109	Pickering B Standby Generator Governor Upgrade	Mar-07
16	49285	Pickering Modify/Replace Fiber Reinforced Plastic Components During 2010 Vacuum Buiding Outage	Apr-10
17	62568	Feeder Repair by Weld Overlay	May-09
		PROJECTS NOT IN EB-2013-0321	

Tab No.	Project Number	Business Case Summary (BCS) Title	BCS Approval Date
18	31518	Darlington Restore Emergency Service Water and Firewater Margins	Feb-14
19	31524	Darlington Station Roofs Replacement	Nov-12
20	31532	Darlington Powerhouse Water Air Conditioning Units Replacement	Feb-15
21	31535	Darlington Water Treatment Plant Replacement	Oct-12
22	31542	Darlington Transformer Multi-Gas Analyzer Installation	May-15
23	31544	Darlington Radiation Detection Equipment Obsolescence	Jan-14
24	31552	Darlington Condenser Circulating Water and Low Pressure Service Water Travelling Screens Replacement	Jun-15
25	31710	Darlington Shutdown Cooling Heat Exchanger Replacement	Apr-14
26	31716	Darlington Neutron Overpower & Ion Chamber Amplifier Replacement (Reactor Regulating System, Shutdown System 1 & Shutdown System 2)	Oct-15
27	38948	Darlington Zebra Mussel Mitigation Improvements	Oct-15
28	73706	Darlington Highway 401 and Holt Road Interchange	Nov-13
29	80022	Darlington OH180 Aging Management Hardware Installation	Dec-14
30	80078	Darlington Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management	Nov-15
31	80111	Darlington Generator Stator Core Spare	Sep-15
32	82816	Darlington Vault Cooling Coil Replacement	Dec-15
33	73566 80144	Darlington Primary Heat Transport Pump Motor Replacement/Overhaul	Jul-15
34	40976	Pickering B Fuel Handling Reliability Modifications	Jun-15
35	41027	Pickering Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	Aug-15
36	66600	Pickering IMS Machine Delivered Scrape	Jul-15

* Projects 31508, 49158 and 49299 are listed as two projects on Ex. D2-1-3 Table 1 (as #31508 and #49158/49299, and are combined in a single Business Case Summary).