CCC Interrogatory #1

Issue Number: 1.1
Issue: Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

Interrogatory

Reference:

Has OPG has been unable to comply with any OEB directions from previous decisions? If so, please provide a list of the directions that OPG has been unable to comply with, and the reasons why compliance could not be achieved.

Response

No, OPG has complied with all OEB directions from previous decisions. Please refer to Ex. A1-11-1.

Board Staff Interrogatory #1

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

Interrogatory

Reference:
Ref: Exh A1-4-1 Attachment 2
Attachment 2 is the Memorandum of Agreement between the Shareholder and OPG, dated July 17, 2015.

a) The previous memorandum was dated August 17, 2005. Under what circumstances is the memorandum revised?

b) What circumstances required the July 17, 2015 revision?

c) Please summarize the differences between the August 17, 2005 and July 17, 2015 memoranda.

Response

a) and b)
Both the Shareholder and OPG agreed that the Memorandum of Agreement (MOA) needed revision because:

- Electricity policy and OPG's operating environment had changed considerably since 2005.
- It is a requirement under the Province's Agency Establishment and Accountability Directive that Ministries refresh MOAs every five years in recognition that MOAs should be reviewed/updated regularly as part of good governance (periodic review and update is a consistent practice applied by the Government of Ontario with its other agencies).
- A desire by the Shareholder to derive enhanced value from its electricity sector agencies.

c) A summary of key changes is provided below. The revised MOA:

- Broadens OPG's business mandate to include a full range of generation technologies and related energy businesses, participation in all Ontario energy-related procurements (s. 4.11) and the ability to pursue strategic investments and acquisitions in the electricity sector, including related business ventures outside Ontario (s. 4.2).
- Reinforces OPG's commercial orientation and that OPG shall achieve financial sustainability, including earning a commercial return (ss. 4.9, 4.10).
- Acknowledges OPG's "public power" role in the sector in delivering value both to Ontario's ratepayers and taxpayers (s. 4.7).

- Updates and clarifies reporting and communication expectations (s. 5).
- Sets performance expectations that reflect more business appropriate language to allow for differences in the underlying nature and role of OPG's assets in comparison to others (s. 6.1.3).

Board Staff Interrogatory #2

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

Interrogatory

Reference:
Ref: Exh A2-1-1, Attachment 3, Page 120

OPG received exemptive relief from the Ontario Securities Commission requirements to allow it to file consolidated financial statements based on US GAAP without becoming a US Securities and Exchange Commission registrant or issuing public debt. This exemption was received in the first quarter of 2014 and is effective until the earlier of January 1, 2019, the year after OPG ceases to have rate regulated activities or the date the International Accounting Standards Board prescribes the mandatory application of an IFRS standard to rate regulated entities.

a) Please explain OPG's plans when any of these conditions are met with respect to the accounting standard to be used going forward.

b) Please explain the potential rate setting impact since at least one of these conditions will be met during OPG's test period (i.e. January 1, 2019).

Response

a) OPG is in the process of assessing potential options should the Ontario Securities Commission (OSC) exemption lapse under one of the three conditions referenced in the question. The company's plans in this regard have not been finalized and may depend on which of the three conditions is triggered. OPG's current thinking related to the three conditions is summarized below.

   Before turning to the specifics, OPG notes that should the OSC exemption lapse and OPG be required to prepare a set of financial statements in accordance with IFRS for public filing purposes, the company would continue to prepare a set of statutory financial statements (and therefore maintain a set of financial records) under US GAAP as required by O. Reg. 395/11 under the *Financial Administration Act (Ontario)* (see Ex. A2-1-1 Att. 3, page 120). OPG would bring the matter to the OEB's attention.

   1) OPG ceases to have rate regulated activities – As OPG would no longer be subject to rate regulation by the OEB, the company's plans in this scenario would not impact the rate-setting process.

2) January 1, 2019 – This trigger would apply if the International Accounting Standards Board (IASB) has not issued and made effective, by this date, its decision on how rate regulated accounting is to be addressed by IFRS. If it becomes reasonably likely that an IASB decision on the rate regulated accounting standard under IFRS will not be finalized with an effective date of January 1, 2019, OPG would consider whether to seek the OSC's authorization for continued application of US GAAP for public filing purposes. A contributing factor to the OSC requirements for disclosure is the reliance that stakeholders place on the financial information reported by OPG. The extent to which OPG has U.S. investors as its capital holders would factor into the ultimate determination of OPG's reporting standard.

3) The International Accounting Standards Board prescribes the mandatory application of an IFRS standard to rate regulated entities – The IASB project on rate regulated activities has been ongoing for several years and is expected to provide greater clarity regarding the application of IFRS standards to rate regulated entities. Upon the outcome of the project, OPG would assess its options regarding reporting standards, taking into account such factors as: the nature of the IFRS standard determined to be applicable to rate regulated entities, the likelihood of obtaining the OSC's authorization for continued application of US GAAP, the reliance placed on the company's financial statements by investors, and the potential implications on the rate-setting process.

b) OPG has not assessed the potential rate-setting impact of IFRS during the IR Term. Should OPG be required to adopt IFRS for public financial disclosure purposes, OPG would bring the matter to the OEB's attention.

Board Staff Interrogatory #3

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

Interrogatory

Reference:
Ref: Exh A2-2-1, Attachment 2

The 2016-2018 Business Planning Instructions are dated May 29, 2015. Have the 2017-2019 Business Planning Instructions been issued? If yes, please provide a copy.

Response

Yes, the 2017-2019 Business Planning Instructions have been issued. A copy is attached (which includes confidential content as marked).

2017-2019 Business Planning Instructions

Issued by:
Finance – Business Planning and Reporting

May 31, 2016

CONTACT INFORMATION	
If you require further information on business planning assumptions, schedules, or requirements, please contact:	
Anthony Melaragno – Senior Manager, Financial Forecasts	400-4646
Vassa Chase – Director, Business Planning & Regulatory Finance	400-3272
Alex Kogan – Vice-President, Business Planning & Reporting	400-3103

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1.0 BUSINESS PLANNING CONTEXT AND ASSUMPTIONS

1.1 BUSINESS PLANNING CONTEXT

CONTACTS: ANDY TEICHMAN / ALEX KOGAN

OPG's 2017-2019 business planning cycle takes place against a more certain, but still challenging planning environment characterized by the following:

- Decisions to refurbish the four nuclear units at the Darlington station and the six nuclear units at the Bruce stations
- Inherent uncertainty in the outcome of OPG's recently filed 5-year nuclear and hydroelectric rate application to the Ontario Energy Board (OEB), which will be a major driver of OPG's financial performance over the planning period
- Increasing focus on managing Ontario's carbon emissions through development of a climate change action plan and Cap and Trade program
- Ongoing pressures to contain electricity cost increases, including continuing scrutiny of the electricity sector by various stakeholders and the public on matters related to cost transparency, efficiency, performance and project management
- Continuing Government focus on deficit elimination, which underscores the importance of OPG meeting its fiscal commitments by achieving net income targets and earning an appropriate return on shareholder's equity
- Continuing weak Ontario electricity demand growth and ample supply, with surplus power conditions projected to continue through to the early 2020s
- Considerable competition for a shrinking pool of new generation development opportunities in Ontario
- Development of Ontario's next Long-Term Energy Plan (LTEP) update, expected by mid-2017

In this planning environment, OPG needs to remain focused on delivering on its business planning commitments in the areas of operational, project and financial performance, without compromising safe and reliable operations. OPG also need sto maintain sufficient planning flexibility to respond to changes in the external environment.

1.1.1 Key Strategic Goals and Imperatives

OPG's mission is to deliver **Power with Purpose** by **providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and the company's shareholder**.

OPG's key longer term goals include:

- Achieving returns on the shareholder's equity in line with OEB-approved levels
- Maintaining the company's substantial generation price advantage for the benefit of customers
- Establishing business growth platforms to replace Pickering's retiring generation
- Building a diverse and engaged workforce and the culture to succeed in the future

Achievement of these goals is supported by key strategic imperatives, enterprise-level initiatives, and a set of medium-term performance goals focused on Net Income, Return on Equity, and Darlington Refurbishment Execution Effectiveness.

The four key strategic imperatives that serve as the foundation for OPG's success are as follows:

Operational Excellence – Focus on continued safe, reliable, efficient, and environmentally responsible operating performance of OPG's generating fleet, and deliver on the following key initiatives:

- Achieve extended Pickering operations as planned and prepare the company for the end of the station's commercial operation
- Pursue business optimization initiatives and identify further opportunities for efficiencies in the company's cost structure
- Develop and implement a flexible human resourcing strategy in support of the company's current and future business needs

Project Excellence – Manage all projects responsibly and deliver them on time, on budget and with high quality. This includes delivering on the following key initiatives:

- Execute work and operational improvements during the Darlington refurbishment to ensure industry leading station operating performance and cost structure post refurbishment
- Develop a project management Centre of Excellence to improve project outcomes across the enterprise

Financial Strength – Enhance OPG's financial strength by strengthening the company's commercial focus, financial flexibility and risk management capability, achieving requested regulated rate application outcomes, and expanding the core generation business. This includes delivering on the following key initiatives:

- Continue to build a constructive relationship with the OEB and align the organization to support successful rate application outcomes
- Improve returns on the shareholder's equity by focusing on bottom line results and migrating towards a regulatory capital structure
- [redacted]

Social Licence – Build and maintain the trust of all external stakeholders, including indigenous communities and other communities in which the company operates, and continue to fully engage employees. This includes delivering on the following key initiatives:

- Build and maintain partnerships with stakeholders through commitment to transparency, accountability and high standards of corporate citizenship
- Continue to promote a strong value-based corporate culture focused on safety, performance excellence, continuous improvement and public trust

1.2 BUSINESS PLANNING PROCESS ENHANCEMENTS

CONTACT: VASSA CHASE

The 2017-2019 business planning process will continue to leverage planning process and system enhancements implemented over the last several years. It will also introduce several new changes. Key highlights are as follows:

- **Financial projection for 2020-2021:** Although the plan continues to cover a period of three years, Business Units and Support Services (collectively, BUs) are requested to provide a financial projection for 2020 and 2021, in line with the period covered by OPG's recent rate application to the OEB (see sections 1.3 and 3.5)
- **Leveraging planning system for longer-term planning:** Submissions of longer-term planning information are required to be made through the business planning system. For the 2017-2019 planning cycle, this will allow leveraging of last year's 2019-2021 financial projection loaded into the planning system, which is expected to reduce planning effort.
- **Targets for Earnings Before Interest and Taxes (EBIT):** Targets for EBIT for the generation segments are being introduced in this planning cycle, to reflect the company's focus on enhancing financial performance and delivering shareholder value (see section 2.0)
- **Retaining earlier submission date:** The previously advanced date of end of July is retained for this year's initial BU business plan submissions (see section 4.0)
- **Simplified labour rate approach:** The same standard labour rates (including payroll burdens) as in the 2016-2018 Business Plan (BP) and 2019-2021 financial projection will be maintained throughout this year's entire planning cycle, which is expected to reduce planning effort. Labour rate differences will be planned centrally at the corporate level.
- **Continued focus on planning and budgeting detail:** The level of planning and budgeting detail continues to be reviewed and, where appropriate, reduced. This includes continuing to apply minimum requirements for maintaining separate Responsibility Centres (RCs), streamlining the use of "Local" identifiers, and separating certain planning and budgeting activity for non-labour costs. (see sections 3.3 and 3.4)
- **Process standardization for planning inter-business unit work and budget transfers:** The requirement to identify and confirm planned inter-business unit work for others in accordance with OPG's cost model is being expanded this year to include a formal sign-off process and schedule. Similarly, in standardizing the budget transfer process during business plan development, a formal sign-off and schedule are also being introduced. (see section 3.1)

- **Common template for business plan materials:** A standardized template for CEO/Enterprise Leadership Team (ELT) BU business plan review materials (see section 5.1.3) and Board of Directors' submissions will be implemented. In addition, the CEO/ELT BU business plan review process is expected to be reviewed in the coming months with a view to streamline as appropriate. Further details will be communicated.
- **Adherence to business planning deliverables and schedule:** Periodic ELT-level reporting on adherence to business plan deliverables and schedule is being implemented this year, as part of the effort to drive a reduction in planning cycle time and rework (see section 3.2)
- **Focus on monthly trending:** As part of detailed budgeting for 2017, particular focus should be directed on ensuring representative monthly trending (for all funding streams) to support effective budget-to-actual reporting

Finance will continue to evaluate opportunities for further standardizing and streamlining of the planning process as part of future business planning cycles. This will include a focus on shortening the planning cycle and further enhancements to the business planning system to gain efficiencies (e.g., automation of certain corporate-level consolidation processes).

1.3 REGULATED REVENUE ASSUMPTIONS

CONTACT: RANDY PUGH

As in past business plans, Business Planning & Performance Reporting (BP&PR) will apply regulated rate revenue assumptions to the 2017-2019 BP, as determined in consultation with Regulatory Affairs.

In May 2016, OPG submitted a nuclear and hydroelectric rate application to the OEB covering the period 2017-2021, for new regulated rates to be effective at the beginning of 2017. If granted in full, OPG's application would equate to a $1.05/month increase on the average customer's bill annually. For the nuclear assets, OPG developed a five-year custom incentive regulation application based on the OPG Board-approved 2016-2018 BP (including a financial projection for 2019-2021). The nuclear request includes a stretch factor that challenges the company to reduce OM&A expenses beyond planned levels starting in 2018, as well as a rate smoothing proposal to mitigate customer impacts by deferring recovery of a portion of revenues to the post Darlington refurbishment period. For the hydroelectric assets, OPG's submission is based on a traditional price cap incentive rate-setting mechanism, which, if approved, would see current approved base rates escalate at inflation less an efficiency factor off the existing base rates with some adjustments. A decision on the application is expected in the first half of 2017.

Pursuant to the OEB's Rules of Practice and Procedure, during the course of the rate application, OPG will be required to bring forward any material changes to its forecasts affecting the 2017-2021 rate period.

1.4 COLLECTIVE AGREEMENTS

CONTACTS: MATT DOWDLE / TERRY FITZPATRICK

The 2017-2019 BP will reflect the collective agreements reached with the Power Workers' Union (PWU) and Society of Energy Professionals (Society) in 2015, effective April 1, 2015 and January 1, 2016, respectively.

BUs should consider the impacts of their planned staffing mix when Pickering ceases commercial operation. In consultation with HR Business Partners, staffing plans should identify opportunities to use temporary staff, including PWU term employees, where this would support current safe and effective operations and mitigate future layoffs and disruption, consistent with collective agreement provisions.

1.5 OPERATING AND OTHER PLANNING ASSUMPTIONS

CONTACT: VASSA CHASE

The following assumptions form the planning basis for the 2017-2019 BP:

2017-2019 Business Plan Assumptions	
Pickering	• End of life for Pickering Units 1 and 4 at the end of 2022 and Units 5 - 8 at the end of 2024 • Pickering operating licence renewal in 2018 spans the Pickering Extended Operations period • Pickering Extended Operations enabling activities are carried out consistent with the approved business case • Maintenance and operating activities support the safe and reliable operation of the units throughout the planning period, with planned outages on a 24-month frequency • Vacuum Building outage in 2021 (30-day outage for all six units) • Preparation activities required to directly support the safe storage of the units will be funded from the nuclear Decommissioning Segregated Fund
Darlington	• Outage plan is based on all units meeting the refurbishment schedule without idle time • The Unit 2 Turbine Generator Controls replacement takes place in 2022 • Post-refurbishment performance of Unit 2 reflects industry operating experience • Plant investments take into consideration life cycle plans and regulatory requirements and commitments, and are aligned with the refurbishment • During the business planning period, planning efforts continue to permit the life extension of the Tritium Removal Facility
Darlington Refurbishment	• The refurbishment outage for the first unit (Unit 2) commences in October 2016 and is completed by February 2020 • Province's approval is received to proceed with the refurbishment of the second unit starting immediately after the first unit is returned to service, as well as the third unit starting in 2021
Nuclear Waste Management	• Assumed receipt of currently pending construction licence enables the L&ILW DGR to be targeted for in-service approximately at the end of 2025 • A waste minimization and reduction program continues to be implemented, with a focus on the efficient management of nuclear waste material currently in storage and as generated at the sites • Loading of dry storage containers is maintained at the Darlington and Pickering Waste Management Facilities, and at a sustainable level for Bruce Power • Used fuel and L&ILW volumes from the Bruce units are based on information as received from Bruce Power; non-routine refurbishment L&ILW is not reflected pending completion of necessary agreements
Nuclear New Build	• Consistent with Ontario's 2013 Long-Term Energy Plan, the site license for potential nuclear new build continues to be maintained for the planning period

2017-2019 Business Plan Assumptions (cont'd)	

Bruce Power	• Bruce Power continues to lease all units during the planning period under the lease and related agreements amended in December 2015
	• Asset management work and refurbishment are executed in line with the published Amended and Restated Bruce Power Refurbishment Implementation Agreement between Bruce Power and the IESO (ARBPRIA), with first unit (Unit 6) refurbishment scheduled from January 1, 2020 to December 31, 2023
	• Currently approved accounting station end of life dates (in line with ARBPRIA) made effective December 31, 2015 will be reflected in the planning period:
	  ○ Bruce A (Units 1-4) – December 31, 2052
	  ○ Bruce B (Units 5-8) – December 31, 2061

[redacted]	• [redacted]
Hydroelectric	• [redacted] • ***Ranney Falls*** expansion project begins execution in the second quarter of 2017, with the facility in service by December 2019 as part of regulated assets • [redacted] • ***Sir Adam Beck Pump GS reservoir rehabilitation*** is completed and placed in service by March 31, 2017 • ***Sir Adam Beck Units 1 and 2*** are converted from 25 Hz to 60 Hz over the 2018-2020 period • ***Sir Adam Beck 1 canal liner rehabilitation*** takes place over 2020-2021 • Project execution for ***Coniston GS*** and ***Calabogie GS*** redevelopments begins in 2018, with an in service date of December 2020 for both facilities, as part of regulated assets • [redacted] • Incremental expenditures related to the implementation of Provincial Dam Safety Technical Guidelines to be considered
Thermal	• [redacted]

2017-2019 Business Plan Assumptions (cont'd)	
Business and Administrative Services	• Shareholder-directed sale of OPG's Headquarters property (and associated leaseback) takes place effective beginning of April 2017 • IT Cyber Security costs are planned by the BAS organization • Real Estate & Services is accountable for facility requirements outside the protected areas, including roads and bridges
[redacted]	• [redacted] •
Nuclear Segregated Funds and Nuclear Waste & Decommissioning Liabilities	• Investments in nuclear segregated funds grow in line with the ONFA-specified rate • The plan will reflect the December 31, 2015 accounting change to the nuclear waste & decommissioning liabilities • Impacts on nuclear segregated funds and nuclear waste & decommissioning liabilities arising from the 2017 ONFA Reference Plan update process continue to be assessed. The 2017 ONFA Reference Plan is subject to the Province's review and approval.
Accounting Service Lives of OPG-Operated Nuclear Stations	• Current approved accounting station end of life dates made effective December 31, 2015 will be reflected in the planning period: o Pickering – December 31, 2020 o Darlington – December 31, 2052
Interest Capitalization Rate	• Non-project specific interest capitalization rate is 5.0% • Any project specific interest capitalization rates are to be derived in consultation with Treasury
SAVH Rate for Projects	• Planned capital, OM&A project and provision project expenditures to reflect the common SAVH rate of 23% over the planning period
Harmonized Sales Tax	• HST restricted input tax credits for telecommunications, meals and entertainment, specified vehicles, and energy for non-production purposes will be phased out as follows: effective July 1, 2016 – 50%, July 1, 2017 – 25% and July 1, 2018 – 0%. All BUs should reflect the corresponding reduction in costs for these purchases.

2.0 RESOURCE TARGETS

CONTACT: ANTHONY MELARAGNO

OPG's Board of Directors recently approved the 2016-2018 BP including the 2019-2021 financial projection. The 2016-2018 BP built on the significant attrition-based headcount reductions and efficiencies achieved over the previous five years. By emphasizing continuous improvement, the aim of that plan is to ensure that the significant gains made to-date are sustained over the longer term without compromising safe and reliable operations, and to challenge the company to find further sustainable cost reductions and efficiency gains. The 2016-2018 BP also recognized the short-term need to fill emerging critical skill gaps following a period of higher than expected attrition.

This year's business planning process will leverage this recent comprehensive planning effort. As such, the ***targets for regular headcount, OM&A, capital*** and ***provision expenditures*** set out below are largely in line with the 2016-2018 BP and 2019-2021 financial projection, subject to recent organizational changes. As in the prior year, targets for OM&A from ongoing operations reflect specific ***targets for project OM&A***, discussed below.

This year's business planning targets will include EBIT targets for the company's generation segments, as shown below.

Earnings Before Interest and Taxes for Generation Segments [1]

$millions	Targets		
	2017	**2018**	**2019**
Regulated – Nuclear Generation [2]	394	391	405
Regulated – Hydroelectric [3]	510	541	528
[redacted]	[redacted]		

***Note 1*:** Generation segment EBIT is defined as revenue less the following main expenses: fuel/gross revenue charge (GRC), OM&A, depreciation and amortization, and property tax.

***Note 2*:** For every $20M change in Nuclear OM&A expenses (net of regulatory variance accounts), production would have to change by ~0.25 TWh to maintain the same EBIT, taking into consideration the associated fuel implications of the production change.

***Note 3*:** For every $10M change in Regulated – Hydroelectric expenses (net of regulatory variance accounts), production (net of regulatory variance accounts) would have to change by ~0.30 TWh to maintain the same EBIT, taking into consideration the associated GRC implications of the production change.

Although the plan will continue to cover a period of three years, BUs are requested to provide a financial projection for 2020 and 2021, in line with the period covered by OPG's recent rate application discussed in section 1.3. As in the previous planning cycle, the projection for the additional years is to be developed using the same basis and using a consistent process with the 2017-2019 information. While no specific targets are provided for 2020 and 2021, BUs are expected to continue utilizing other planning tools such as benchmarking, other performance indicators and trend analysis to prepare reasonable projections in line with the company's strategic imperatives. Explanations of significant variances from last year's projection will be required.

Regular Headcount Targets

	Targets		
	2017	**2018**	**2019**
Total Nuclear (Excl. Darlington Refurbishment)	5,725	5,709	5,634
Nuclear Projects	*277*	*277*	*267*
Nuclear Operations	*5,448*	*5,432*	*5,367*
Renewable Generation & Power Marketing	[redacted]		
[redacted]			
Total Operations	[redacted]		
Business and Administrative Services	876	866	859
Finance	343	336	329
Assurance	57	57	57
People/Culture & Communications	675	668	672
Legal/Ethics & Compliance	98	97	95
Corporate Office	12	12	12
Total Support Services	**2,061**	**2,036**	**2,024**
Total Ongoing Operations	[redacted]		
Darlington Refurbishment	512	520	545
Total OPG	[redacted]		

Total OM&A Targets*

$ millions	Targets		
	2017	**2018**	**2019**
Nuclear	1,719	1,729	1,764
Nuclear Project Portfolio (Excl. Darlington Refurbishment)	*114*	*109*	*100*
Nuclear Operations - Base & Outage OM&A	*1,605*	*1,620*	*1,664*
Renewable Generation & Power Marketing	[redacted]		
Total Base OM&A			
[redacted]			
Regulated Plants Project OM&A	*79*	*88*	*99*
[redacted]	[redacted]		
Total Operations	[redacted]		
Business and Administrative Services	295	289	292
Base OM&A	*279*	*276*	*279*
Project OM&A	*16*	*13*	*13*
Finance	79	78	78
Insurance	43	47	49
Assurance	12	11	12
People/Culture & Communications	133	131	133
Legal/Ethics & Compliance	33	31	33
Corporate Office	9	9	9
Total Support Services	**604**	**597**	**606**
Total Ongoing Operations	[redacted]		
Darlington Refurbishment**	42	14	4
Nuclear New Build	1	1	1
Total OPG*	[redacted]		

**Excluding centrally-held costs held at the corporate level, cost of goods sold, and the impact of regulatory deferral and variance accounts.*
***Darlington Refurbishment expenditures are consistent with the approved Release Quality Estimate.*

2.1 CAPITAL, PROJECT OM&A, AND NON-ONFA PROVISION-FUNDED PROJECT TARGETS

CONTACT: BOB GERRARD

As in previous years, resource targets for the 2017-2019 BP include ***capital*** and ***project OM&A targets*** for all applicable BUs. In addition, ***targets are provided for non-ONFA provision-funded projects***. The targets are based on the assumptions outlined in section 1.5 and are largely in line with the approved 2016-2018 BP. Material developments affecting those assumptions may necessitate revisions to the targets.

Total Capital Targets

$ millions	Targets		
	2017	**2018**	**2019**
Sustaining Capital			
Total Nuclear (Incl. MFA)	**279**	**258**	**282**
Regulated Hydroelectric Projects (Incl. MFA)	146	111	122
Contracted Generation Portfolio - [redacted]	[redacted]		
Contracted Generation Portfolio (Incl. MFA) - Other Projects			
Total Renewable Generation & Power Marketing	[redacted]		
Business and Administrative Services (Incl. MFA)	45	48	44
Finance	2	1	1
People/Culture & Communications	9	8	9
Legal/Ethics & Compliance	2	1	1
Total Support Services*	**57**	**58**	**54**
Total Sustaining Capital	[redacted]		
Generation Development Capital			
[redacted]	[redacted]		
Sir Adam Beck Units 1 and 2 Conversion	2	17	43
Other	-	-	1
Total Renewable Generation & Power Marketing	[redacted]		
Ranney Falls Expansion	34	19	8
Coniston GS Redevelopment	2	7	19
Calabogie GS Redevelopment	3	8	19
[redacted]	[redacted]		
Other			
Total Business Development	[redacted]		
Darlington Refurbishment*	**1,063**	**1,094**	**951**
Total Generation Development Capital	[redacted]		
Total OPG	[redacted]		

** Darlington Refurbishment expenditures are consistent with the approved Release Quality Estimate. This line item reflects the portion of the Darlington Refurbishment Project capital to be budgeted by the Nuclear business unit. The portions to be budgeted by Support Services are reflected in the corresponding line items.*

Total Project OM&A Targets

$ millions	Targets		
	2017	**2018**	**2019**
Nuclear Project Portfolio (Excl. Darlington Refurbishment)	**114**	**109**	**100**
Renewable Generation & Power Marketing - Regulated Plants	79	88	99
Renewable Generation & Power Marketing - [redacted]	[redacted]		
Total Renewable Generation & Power Marketing	[redacted]		
Business and Administrative Services	16	13	13
Legal/Ethics & Compliance	1	0	0
Total Support Services	**17**	**13**	**13**
Darlington Refurbishment	**42**	**14**	**4**
Nuclear New Build	**1**	**1**	**1**
Total OPG	[redacted]		

Total Nuclear Provision-Funded Project Targets (Excl. ONFA funded)

$ millions	Targets		
	2017	2018	2019
Darlington Refurbishment Retube Waste Containers	32	43	30
Nuclear Waste Management	40	40	40
Total Nuclear Decomissioning and Waste Management Expenditures	**72**	**83**	**70**

2.2 Targets for Nuclear Waste Management and Decommissioning Expenditures

Contact: Banh Tran

In addition to the targets for non-ONFA provision-funded project expenditures on nuclear waste management provided in section 2.1, targets for ONFA provision-funded project expenditures on nuclear waste management and decommissioning activities and all operating expenditures for these activities will be provided by Business Planning & Reporting (BP&R) – Nuclear Waste Management in a separate communication. These targets will be in line with the recently approved 2016-2018 BP, including the 2019-2021 financial projection.

3.0 Key Process Optimization

Contact: Vassa Chase

In addition to continuing to optimize the business planning level of detail as outlined below, this year's planning process introduces the requirement for sign-offs and timelines related to inter-business unit work for others and budget transfers. This is intended to encourage enhanced integration and communication across BUs earlier in the planning cycle, resulting in less potential for rework.

This year's planning cycle will also implement periodic ELT-level reporting (i.e. CFO and business unit leaders) on adherence to BU plan deliverables and schedule. Each of these processes is discussed below.

3.1 Inter-business Unit Work for Others and Budget Transfer Sign-Offs

Contact: Anthony Melaragno

As in previous years, all business planning at OPG is to be conducted in accordance with the single OPG cost model. As discussed further in section 5.8, under the cost model, an organization at OPG plans for all the resources for which it is accountable, regardless of where the resources work or what they work on. The cost model requires identification, communication, agreement and documentation of inter-business unit service needs by operating business units and support service functions as part of developing their respective business plans.

The identification and communication of inter-business unit service needs must occur during the initial phase of the planning process, with a signed agreement required between the service providers and service recipients by July 8, with a copy to the respective controllership organizations. The formal sign-off process at this stage of the planning process will help to ensure that service providers' plans adequately reflect the needs of the service recipients. Service needs for which a signed agreement is not reached between business units are expected to be brought forward to the CEO/CFO/ELT.

In addition, communication regarding budget transfers should occur early in the planning process. Specifically, ***budget transfers between BUs require formal sign-offs by July 8 with a copy to the respective controllership organizations*** in order to ensure that the transfers are incorporated into the 2017-2019 BP. If an organizational change occurs after July 8 and, in particular, after the initial BPC submission date of July 25, BP&PR will evaluate on a case-by-case basis whether the planning system and BU business plans require updating.

3.2 ELT-Level Reporting on Adherence to Business Plan Schedule and Deliverables

Contact: Vassa Chase

In order to shorten the planning cycle and further streamline the planning process, the 2017-2019 business planning cycle will implement periodic ***ELT-level reporting on adherence to BU business plan schedule and deliverables***. The schedule and deliverables are as outlined in sections 4.0 and 5.0, respectively. While further details will be provided in the coming month, it is currently anticipated that reporting will take place around key submission dates such as initial BPC submission, supplementary planning information, finance review sign-offs, business plan materials for CEO review, and draft Board of Directors' memoranda. Additional reporting may be undertaken to highlight areas with significant amounts of preventable rework and/or non-compliance with key requirements set out in these instructions. The reporting may also be used to identify the impact on the planning process of externally or internally-driven changes in assumptions during the planning cycle.

3.3 Streamlining Use of Responsibility Centres and Local Identifiers

Contact: Vassa Chase

Controllers are required to continue their review of all existing RCs to ensure that planning/budgeting occurs only for RCs that have at least 20 employees **and** $5M in combined financial activity (OM&A, capital expenditures, revenues, and provision expenditures). Planning/budgeting can also occur for RCs that meet the following exceptions:

i) Direct reports of ELT members
ii) Facilities with energy supply agreements/commercial contracts
iii) Requirements exist to separate rate-regulated activities

All other exceptions require prior written justification from the local Controller and approval by the respective BU Finance leader (i.e. VP Nuclear Finance, VP Renewable Generation & Power Marketing Finance, Director Controllership for Support Services). Approvals should be forwarded to Director, Business Planning & Regulatory Finance and Director, Management Reporting. Exceptions approved in prior years should be reviewed to ensure that justifications remain valid for the 2017-2019 planning period.

A list of the 2016 RCs from the 2016-2018 BP for the respective organizations can be found on the Finance – Business Planning SharePoint site.

Controllers are also requested to continue to review the planning/budgeting "Local" identifiers for opportunities to reduce the level of detail. Controllers should ensure that the use of "Locals" is consistent within the respective BUs and, in particular, is limited to instances where such identifiers are necessary for reporting and analysis of actual results.

3.4 Planning versus Budgeting

Contact: Vassa Chase

For the 2017-2019 BP, BPC system rollover capability will maintain 2017-2019 information from the approved 2016-2018 BP (including the 2019-2021 financial projection) for OM&A, capital expenditures and provision expenditures. As discussed in section 5.1.2, there will be no changes to standard labour rates (including payroll burdens) from last year's business plan throughout this year's entire planning cycle. As a result, in many instances, it will be appropriate to develop the 2017-2019 planning submissions by making adjustments to the copied BPC data from last year's planning information.

For the initial BPC data load on July 25, labour costs must be planned for all years at the detailed RT level. BUs have the option, for their initial submission only, of using the following higher Major Resource Type levels in making non-labour adjustments to copied data in BPC:

- Managed Tasks	- Facilities & Utilities	- Augmented Staff	- Operating License
- Materials	- Real Estate	- Business Expenses	- Other

If this higher level approach is adopted for the July 25 submissions, BUs may plan against one (or more) RT within each Major Resource Type that is most meaningful to their organization. For a detailed RT listing within each Major Resource Type, refer to the Finance – Business Planning SharePoint site.

Irrespective of the approach adopted, the following specific RTs must also be planned during the initial data load, for tax purposes:

- 240 & 241: Computer Equipment & Hardware
- 242: Computer Software & Licences
- 245: Service Equipment <$25,000
- 246: Transport & Work Equipment

For the initial BPC data load on July 25, the BUs also have the option of making adjustments to last year's planning data at higher level RCs, as follows:

- For Nuclear and Renewable Generation & Power Marketing (RG&PM), station or support group level RCs can be used
- For Support Services, ELT direct report level RCs can be used

The BUs should also consider if some of the "Local" identifiers can be omitted from the initial BPC data load. "Locals" are required for the initial data load only to the extent necessary for meaningful plan-over-plan and year-over-year analyses.

In all circumstances, the overriding principle for the initial BPC data load is to plan in sufficient detail, so as to provide meaningful plan-over-plan and year-over-year analyses.

Budgeting to enable 2017 reporting and facilitate the rollover of 2018 and 2019 planning details into future plans must be completed by ***September 30***. Budgeting requires the pushing down of higher-level planning data to the detailed RT and RC levels, and the use of "Locals" to the extent necessary to enable reporting and analysis of actual results.

No changes to annual planned amounts (OM&A, capital expenditures, revenue, provision expenditures) from the initial July 25 BPC data load can be made on account of finalizing the detailed budgets. The only changes permitted from the initial submission are those resulting from the CEO/ELT reviews or other corporately driven changes, which must be reflected in the BPC budgeting detail by ***September 30***.

3.5 OTHER REQUIREMENTS

CONTACT: VASSA CHASE

- ***Full-time equivalent (FTE) calculations for regular labour costing must use the half-year rule.*** That is, when a regular headcount is added or removed during the year, 0.5 of an FTE must be added or removed in that year for labour costing purposes. There are no exceptions to this requirement without the explicit approval by BP&PR. To facilitate the implementation of this requirement, BUs are requested to submit a reconciliation of year-end headcount and FTE trends over the planning period.

- Although the plan will continue to cover a period of three years, BUs are requested to provide a financial projection for 2020 and 2021. BPC will contain labour rates, including burdens, for these years, which are unchanged from last year's projection for these years. While specific targets are not provided for these years, it is expected that BUs will leverage last year's 2019-2021 financial projection as the starting point. Explanations for significant changes from that projection will be required.

4.0 SCHEDULE

CONTACT: ANTHONY MELARAGNO

The following is the schedule of the key activities for the 2017-2019 business planning process. Business planning activities require significant coordination amongst various organizations during the business planning timeframe. The same planning information may be used by different users but at different times during the business planning process. It is critical to the integrity of the consolidated OPG plan that information provided to different business planning users be consistent.

MONTH	BUSINESS PLANNING ACTIVITY
April – May	• Historical labour data submission by People/Culture & Communication (PC&C) to BP&R – Management Reporting & Forecasting (MR&F) – **by early May** • Completion of labour rate review by MR&F – **May 12** • Business planning approach endorsed by the ELT– **mid May** • Business planning instructions and targets issued – **May 31**
June	• Continuing site and BU plan development
July	• BU submissions of inputs into the Energy Production and Revenue Plan to Finance – Integrated Revenue Planning – **July 4** • Calculations of nuclear fuel bundles (Darlington and Pickering only) provided by BAS – Supply Chain to BP&R – Nuclear Waste Management – **July 4** • Sign-offs on agreed plans for inter-business unit work for others as well as on budget transfers between BUs – **July 8** • BUs [redacted] to RG&PM – Commercial Contracts & Power Marketing – **July 11** • BU submissions of 2017-2019 BPC planning input to BP&PR – **July 25** • Submissions of corporate level information including depreciation, employee incentive costs and other centrally-held costs to BP&PR – **July 25** (see section 5.5 for details)
August	• Review of [redacted] including inputs and assumptions, by senior Finance staff – ***August 2*** (refer to section 5.2 for details) • Finance review and sign-offs by BU Controllers for 2017-2019 are submitted to BP&PR – **August 5** • Energy Production and Revenue Plan submitted by Integrated Revenue Planning to BP&PR – **August 8** • Planning business cases and project information submitted by BUs to Finance – Investment Planning – **August 8** • Initial nuclear asset retirement obligation and nuclear segregated funds balance projection provided to BP&PR by BP&R – Nuclear Waste Management – **August 12** • Finance review and sign-off by Director, Accounting submitted to BP&PR – **August 12** • BUs submit supplementary financial information, analyses and reconciliations to BP&PR, including plan-over-plan and year-over-year analysis – **August 19** • Variance and deferral account information provided by Regulatory Finance – **August 23** • CEO/ELT business plan review materials including Energy Production and Revenue Plan submitted to BP&PR – **August 26**
September	• Draft consolidated 2017-2019 financial results prepared by BP&PR – **mid September** • CEO/ELT reviews of BU business plans – **mid to late-September** • Support Services groups and RG&PM Controllership submit assigned/allocated costs to Support Services Controllership (see section 5.1.4 for details) – **September 20** • Revisions to BU BPC submissions based on CEO/ELT reviews and inclusion of budgeting level detail – no later than **September 30** • Updated Finance reviews and sign-offs (as required) – no later than **September 30**
October	• BUs submit draft Board of Directors business plan memoranda to BP&PR – **October 18** • BUs finalize 2016/2017 monthly trending and update BPC data (no changes to annual amounts are permitted) – **October 28**
November	• Approval of the 2017-2019 BP by OPG's Board of Directors – **November 10**

December	• Finalization of cost allocations and loading of budgets into reporting systems • Issuance and acknowledgement of budget letters • Conversion of planning information to Shareholder's fiscal basis

Note: *Draft planning information may be reviewed with OPG's Shareholder throughout the business planning process.*

5.0 BUSINESS PLANNING AND BUDGETING INSTRUCTIONS

5.1 BUSINESS UNIT INFORMATION SUBMISSIONS

CONTACT: ANTHONY MELARAGNO

Business planning submissions are required from each BU for each of the three years of the 2017-2019 BP by the dates specified in the business planning schedule (see section 4.0). Information submissions will reflect OPG's reporting segment structure: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Contracted Generation Portfolio, and Services, Trading and Other Non-Generation. Further details continue to be required for the RG&PM facilities, as discussed in section 5.3.

BUs will use BPC to submit the majority of financial and headcount information. All other information will continue to be submitted through the Finance – Business Planning SharePoint site. Representatives from each applicable BU were previously identified for purposes of SharePoint access, with responsibility rights granted accordingly. As in the past, individual BU folders will only be accessible by members of that specific BU, as well as the BP&PR team. For questions regarding SharePoint access, contact Kris Rowsell at 400-3378.

The BU submissions should include the following:

July 25 **– Quantitative resource and financial information**

- Submitted through BPC, in accordance with the details in section 5.7
- By RC and RT, in line with the direction provided in section 3.3 and 3.4
- The initial submission must contain summarized monthly detail for 2017 and 2018, with emphasis on realistic forecasts for the first quarter of each year (for Shareholder's fiscal year-end purposes) and annual information for 2019
- **Any changes to planning submissions subsequent to July 25, other than those explicitly contemplated by these instructions, must be reported to, and confirmed with BP&PR.**

August 19 **– Supplementary financial information and supporting year-over-year, plan-over-plan and plan-to-target analyses**

- Year-over-year analysis of changes in resources (e.g., regular and non-regular headcount, base OM&A, project OM&A, outage OM&A, capital expenditures, non-generation revenues and cost of goods sold, and provision expenditures)
    - Analysis should be provided in the form of a year-over-year continuity (roll) in a level of detail that is sufficient to fully explain the major drivers contributing to the change
    - Work program changes should be separated from rate changes
    - Analysis should include year-end 2016 projections assumed in preparing year-over-year changes
- Plan-over-plan comparison (2017-2019 BP versus 2016-2018 BP)
- Plan-to-target reconciliations including drivers of variance
- Submitted through the Finance – Business Planning SharePoint site in the form of Excel spreadsheets and/or other documents.

August 26 **– Business Plan materials for CEO/ELT reviews** (refer to section 5.1.3 for details)

5.1.1 Specific Information Requirements

CONTACT: ANTHONY MELARAGNO

OM&A

- OM&A expenses reconciled to total OM&A targets outlined in section 2.0, with project OM&A reconciled to project OM&A targets outlined in section 2.1
  - If the submission exceeds targets, reconciliations should identify specific sources of variance from targets, underlying drivers, and mitigation measures taken

- Year-over-year and plan-over-plan analyses should specifically identify material changes driven by outage profiles, non-standard projects, or non-recurring or infrequent events
  - Significant drivers for non-labour resource changes should be separately identified
  - Nuclear outage OM&A analysis should be provided including a summary of scope, outage duration and incremental OM&A costs.

Staffing

- Details of regular and non-regular year-end headcount (temporary and term employees but excluding augmented staff), including regular headcount reconciled to the targets outlined in section 2.0, and FTE funding for each of regular and non-regular labour
  - If the submission exceeds targets, reconciliations should identify specific sources of variance from targets, underlying drivers, and mitigation measures taken
  - Summary headcount analyses, including projected attrition, hiring, and plans to meet the hiring demand including the use of temporary and contract resources, as applicable, should be provided
  - A reconciliation of year-end headcount and FTE trends over the planning period.

Capital

- Capital expenditures, including intangible assets and capital spares, balanced to project listings, as directed in section 5.9, and expenditures on minor fixed assets, together reconciled to capital targets outlined in section 2.1
  - Reconciliations should identify specific reasons for variance and underlying drivers
- Expenditures on capital spares should continue to be identified and input into BPC as a separate classification
- Consistent with capital project plan BPC details and project lists, the following is to be provided:
  - Capitalized interest forecasts on a monthly basis for 2017 and 2018 and annually for 2019, including forecasts for any supplemental adjustments
  - In-service addition forecasts on a quarterly basis for all three years, including in-service addition forecasts for any supplemental adjustments. Monthly details are required where a single in-service addition is at least $50M, as well as for all Darlington refurbishment amounts. In addition, in-service addition forecasts are required for the third and fourth quarters of 2016.
  - Quarterly asset retirements/write-offs forecasts are to be provided for all three years. Monthly detail is required where a single asset retirement/write-off planned is at least $50M.

Fuel Expense

- The following fuel expense details must be submitted to BP&PR and Integrated Revenue Planning as part of the inputs into the Energy Production and Revenue Plan, which is ***due on July 4:***
  - Nuclear fuel
  - GRC and related costs – both excluding and including forgone production due to surplus baseload generation conditions
  - [redacted] for thermal stations.

Provision Expenditures/Provisions

- Nuclear decommissioning and waste management provision expenditures, in line with guidance provided in section 5.1.5
  - Expenditures should be provided for:
    - Decommissioning – Pickering Units 2 & 3, Pickering Units 1 & 4, Pickering Units 5-8, and Decommissioning Oversight
    - Used Fuel Storage
    - Low and Intermediate Level Waste – Operations

  - Expenditures should be reconciled to targets to be provided by BP&R – Nuclear Waste Management (see section 2.2)
  - If submissions exceed targets, reconciliations should identify specific sources of variance, and underlying drivers
- New provisions or provision updates (First Nations and other) expected during the planning period
- Draw downs of existing provisions (e.g., First Nations, [redacted] environmental, [redacted]

Nuclear Segregated Funds

- Submission of planning information for reimbursements from the nuclear segregated funds must be consistent with the planned draw downs of the nuclear decommissioning and waste management provision, and will be coordinated by BP&R – Nuclear Waste Management

Working Capital Items

- Monthly detail for 2017 and annual detail for 2018 and 2019 for the following:
  - Fuel inventory
  - Materials and supplies inventory

Nuclear Outages

- Summary nuclear outage schedule by facility for the planning period

Revenue and Gross Margin

- As outlined in section 5.2

5.1.2 Payroll Burden

CONTACT: VASSA CHASE

This year's business planning process will see a simplified approach to standard labour rates including payroll burden rates, by keeping them unchanged from those in the 2016-2018 BP and the 2019-2021 financial projection. The impact of any subsequent changes to 2017-2021 planned burdens (either positive or negative) will form part of the business plan by being held centrally at the corporate level. Actual standard labour rates including payroll burdens for 2017 will be set equal to the planned amounts reflected in BU business plans, with the difference relative to actual amounts journalized monthly to a centrally-held account, as in prior years. The 2016-2018 BP did not contain any BU-leader level burden amounts for 2017 onwards and none will be reflected in this year's planning cycle.

As in prior years, costs relating to employee incentive plans will be budgeted as a centrally-held cost at the corporate level.

For further details regarding the use of BPC for the 2017-2019 business planning cycle, refer to section 5.7.

5.1.3 Business Plan Materials for CEO Review

CONTACT: VASSA CHASE

The CEO/ELT review process for BU business plans is under review. The review will seek to streamline the process and focus the review on key issues. While the outcome of the review will be communicated in the coming months, it is expected that draft BU business plan materials will still be required to be submitted for CEO, CFO and/or ELT review in some form by mid to late-September, based on the BPC submissions. Such draft materials (in the form to be specified) are to be provided to BP&PR on ***August 26***.

A template for these materials containing the minimum requirements will be provided on the Finance – Business Planning SharePoint site. Additional information may be added in the appendices. Submissions of completed templates are to be made through the Finance – Business Planning SharePoint site.

Pending the completion of the CEO/ELT process review and issuance of the template, the following provides, for reference, the minimum requirements for BU business plan materials based on the 2016-2018 Business Planning Instructions. It is expected that many of these elements will feature in this year's template.

- Strategic Objectives & Key Operating Performance Measures over the planning period

- Key Planning Assumptions
- Financial Plan – Including 2016 year-end projection
    - BUs that have major work performed by groups outside of their organization (e.g., Darlington refurbishment) should note the cost of such planned work in order to present a complete cost of the project or work program
- Staff Plan – Including summary hiring plan to meet planned labour demand over 2017-2019 and 2016 year-end projection (including use of PWU term, temporary and contract resources, as applicable)
- Generation Plan (as applicable)
- Key Initiatives – Including strategic sourcing initiatives and resulting savings reflected in the financial plans
- Program Write-ups
- Plan-over-Plan Comparisons (2017-2019 BP versus 2016-2018 BP) – Including analyses of changes in resources (OM&A, capital expenditures, provision expenditures, headcount) and programs
- Plan-to-Target Comparisons – Including drivers of variance and steps taken to mitigate submissions in excess of targets
- Year-over-Year Changes – Including explanations of material factors contributing to the changes
- Risks and mitigation strategies incorporating the requirements of section 6.1.2.

As in previous years, Integrated Revenue Planning is required to submit to BP&PR, by ***August 26,*** a presentation summarizing the Energy Production and Revenue Plan, including key assumptions, dependencies, risks, and major changes from last year's plan.

5.1.4 Cost Allocations for Support Services and RG&PM

CONTACTS: JENNY RUZ / MICHELLE GIRARD

Support Services and RG&PM groups are required to assign/allocate all submitted costs on the basis of OPG's cost model and in line with the current reporting segment structure and RG&PM information requirements in section 5.3. Support Services and RG&PM groups are expected to provide the rationale for any management estimates made for the purposes of cost assignment/allocations. As in prior years, a template for this information will be provided by, and must be submitted to, Support Services Controllership.

RG&PM site Controllers are also required to submit to Support Services Controllership allocation factors between regulated and contracted plants, where applicable, for all years of the business plan. These factors must continue to be applied consistently across the RG&PM operations in accordance with established methodologies.

The recent organizational changes have not resulted in changes to allocation methodologies.

The submission date for the above information is ***September 20***.

5.1.5 Nuclear Provision Expenditures

CONTACTS: BANH TRAN / CYNTHIA DOMJANCIC

Planning for nuclear decommissioning and waste management provision expenditures requires the same rigour and change management process as OM&A and capital expenditures. Similar to OM&A, provision programs are classified as either base or project. The executive sponsor responsible for scope, life-to-date and annual expenditures is the SVP Decommissioning and Nuclear Waste Management (D&NWM) who submits the consolidated budget for approval to the Nuclear President & Chief Nuclear Officer.

Only expenditures that are directly attributable to nuclear waste management and decommissioning activities and included in the provision should be planned as provision expenditures.

Directly attributable, for the purposes of nuclear provision expenditures, is defined as follows:

- For support groups such as PC&C, Regulatory Affairs, Finance, and BAS directly attributable is defined as:
    - Costs of staff that are fully dedicated to the support of the nuclear waste management and decommissioning programs. ***Timesheet tracking of partial support from multiple employees does not qualify.***

- Staff working on nuclear waste management and decommissioning specific project activities and work programs as a normal part of their function. These work activities will be tracked within the Tempus time reporting system.

The Nuclear business planning team and Support Services controllership are required to submit nuclear provision funding and headcount requests to the D&NWM Finance Controller by ***July 5***. The Finance Controller will coordinate reviews/approvals and will provide the approved consolidated funding and headcount levels to the Nuclear business planning team and Support Services controllership by ***July 8*** for inclusion in their respective business plans.

Business planning for nuclear provision expenditures must follow the schedule and process set out in these instructions, including loading of BPC data, requirements for supplementary analyses, and business plan presentation content.

Any changes to planning submissions for provision expenditures after July 25, other than those explicitly contemplated by these instructions, must be reported to, and confirmed with BP&PR. These changes must also be reported to BP&R – Nuclear Waste Management.

5.1.6 Pickering Extension Costs

CONTACT: HAMANT BECHARBHAI

During last year's business planning cycle, the PEXT project group in BPC was used to collect all incremental costs related to the planned extension of the end of Pickering commercial operations from 2020 to 2022/2024. Extended Pickering operations are the base case planning assumption for this year's planning cycle.

The Pickering Extension business case identified two components of Pickering Extension incremental costs:

1. Enabling costs – Incremental Nuclear costs directly necessary to enable extended operations (up to 2020 only)
2. Normal Extension costs – Additional ongoing Nuclear and corporate Support Services costs (up to 2024) that would need to continue while Pickering is operating

For the 2017-2019 BP and the associated 2020-2021 financial projection, the PEXT project group is to be used ***only*** by the Nuclear business unit for Enabling costs up to 2020, as defined by the Pickering Extension business case. Nuclear organizations should refer to information issued by Nuclear Business Planning for the breakdown between Enabling and Normal Extension costs.

Planners are ***not to use the PEXT project group for Normal Extension costs***, and therefore need to reassign these costs to other appropriate projects in BPC. This includes corporate ***Support Services who are not to use any PEXT projects for this year's plan*** and should reassign their base plan from Project 82828 to Project 00000 in BPC.

For reference, the PEXT project group currently includes the following project numbers, which will now be used only by the Nuclear business unit for Enabling costs up to 2020:

- Under FAC 62000, projects #82828
- Under FAC 62020, projects #82829, 82830, 82831, 82832, 82833 and 82834
- Under FAC 62030, projects #80157 and 82944
- Under FAC 17533, project #82945

5.2 REVENUE AND GROSS MARGIN SUBMISSIONS

CONTACTS: BILL WILBUR / VASSA CHASE

The accountabilities for revenue and gross margin information submissions to BP&PR are outlined below. Any sources of revenue not listed that are expected during the planning period should be identified to BP&PR and Integrated Revenue Planning by the group responsible for managing the revenue source.

BU submissions of inputs into the Energy Production and Revenue Plan are to be provided to Integrated

Revenue Planning by ***July 4***. Specific information requirements for inputs into the Energy Production and Revenue Plan will be communicated by Integrated Revenue Planning.

Cost inputs for determining [redacted] must be submitted to RG&PM – Commercial Contracts & Power Marketing by ***July 11***. If there are changes to these inputs following July 11, updated information must be provided to RG&PM Commercial Contracts & Power Marketing as soon as possible.

By ***August 2***, [redacted] including inputs and assumptions, will be jointly reviewed by RG&PM – Commercial Contracts & Power Marketing, Integrated Revenue Planning, and senior Finance staff from RG&PM Controllership, Shared Financial Services – Revenue Accounting & Reporting, and BP&PR.

Unless otherwise specifically noted in the business planning schedule, the below revenue and gross margin submissions are due to BP&PR on ***July 25.***

REVENUE SOURCE	BUSINESS PLANNING ACCOUNTABILITY
Generation/Capacity Revenue (incl. new projects) • [redacted] • Ancillary and other revenues	Integrated Revenue Planning *(as part of the Energy Production and Revenue Plan)* BP&PR will apply regulated rate assumptions to compute regulated generation revenues
[redacted]	Commercial Contracts & Power Marketing
Nuclear Non-Generation Revenue* • Isotope Sales, Heavy Water, Detritiation Sales and Services • Bruce Lease Rent and L&ILW Services	BAS – Supply Chain BAS – Real Estate & Services *(Cost of Goods Sold)*
Nuclear Non-Generation Revenue* • Engineering Services • Investment Recovery	Nuclear
[redacted]	[redacted]
[redacted]	[redacted]
Renewable Generation & Power Marketing Non-Generation Revenue*	RG&PM
Training and Other Revenue*	PC&C

****For items marked with an asterisk in the table above, the identified groups are responsible for inputting the planning submission into BPC, including monthly trending for 2016 and 2017.***

5.3 INFORMATION REQUIREMENTS FOR RG&PM FACILITIES

CONTACT: ANTHONY MELARAGNO

Where applicable, RG&PM detailed planning submissions should continue to provide information for each of the facilities or groupings listed below. For the purposes of the RG&PM business plan materials for CEO/ELT review, it is expected that information will be aggregated, as appropriate, consistent with OPG's segment reporting structure.

The specific RG&PM facilities/groupings are as follows:

- Niagara Operations
- Saunders GS
- Eastern Operations – excluding Saunders GS and Lennox GS
- [redacted]
- Central Operations – excluding [redacted]

- [redacted]
- Northeast Operations – excluding [redacted]
- Northwest Operations – excluding [redacted]

The submissions should address all applicable information requirements outlined in these instructions for each of the above facilities/groupings. Directly attributed and allocated RG&PM regional operations and RG&PM central office OM&A should be shown separately.

5.4 NON-CONTROLLING INTEREST AND INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

CONTACT: VASSA CHASE

[redacted]

5.5 OTHER INFORMATION SUBMISSIONS

CONTACT: ANTHONY MELARAGNO

The accountabilities for information submissions related to other cost items for the 2017-2019 BP are outlined below. While BP&PR may initially receive some of these items from groups other than those identified below, it remains the responsibility of the accountable group to make the formal submissions in accordance with the business planning schedule. Key assumptions and dependencies should be identified in the submissions.

ITEM	BUSINESS PLANNING ACCOUNTABILITY
Depreciation/Amortization – ***July 25*** ○ Based on current net book values of fixed/ intangible assets, and station end-of-life dates/average asset class service lives expected to be in effect during the planning period, including any changes expected from the Depreciation Review Committee process	Finance – Shared Financial Services – Accounting
Property Tax (separately showing amounts to be charged against decommissioning provisions and amount to be capitalized) – ***July 25***	BAS – Real Estate & Services – Property Assessment and Taxation

Insurance – ***July 25*** ○ Summary of underlying assumptions ○ Amounts to be charged against decommissioning provisions and amounts to be capitalized to be shown separately	Finance – Treasury *(costs submitted as part of the Finance BPC submission)*
Employee incentive plans (centrally-held cost) – ***July 25***	PC&C – Total Rewards & Solutions Centre
Vacation accrual and fiscal calendar adjustment (centrally-held costs) – ***July 25***	Finance – Shared Financial Services – Accounting
Pension Guarantee Fee (centrally-held cost) – ***July 25***	Finance – Treasury
Accretion on Nuclear Waste Obligations and Earnings on Nuclear Segregated Funds – ***August 12***	Finance – BP&R – Nuclear Waste Management
Pension and OPEB Costs – update by ***August 16***	Finance – BP&R – Actuarial
Deferral and Variance Accounts – by ***August 23***	Finance – BP&R – Regulatory Finance
Asset Service Fees, Accretion on Non-Nuclear Decommissioning Obligations, and Interest Expense	Finance – BP&PR *(for interest, reflecting inputs from Treasury and capitalized interest from BUs)*
Income Taxes and HST Restricted Input Tax Credits (centrally-held cost)	Finance – Income Tax

5.6 FINANCE REVIEW AND SIGN-OFF

CONTACT: VASSA CHASE

The following senior Finance staff will complete and submit to BP&PR a financial review and sign-off for the business planning submissions for the groups that they support/represent:

- All BU Controllers by ***August 5*** (**note:** Non-generation revenue will be included in the review and sign-off by Support Services Controllership)
- VP Renewable Generation & Power Marketing Finance, Director Accounting, and Director Business Planning & Regulatory Finance jointly by ***August 12*** – [redacted]
- Director, Accounting by ***August 12*** – depreciation & amortization (excluding amortization of deferral and variance accounts) and centrally-held costs per section 5.5, as well as inputs to BP&R – Nuclear Waste Management for nuclear waste obligations and segregated funds
- Senior Manager, Nuclear Waste Management by ***August 12*** – nuclear decommissioning and waste management obligations based on inputs provided
- Director, External Reporting & Accounting Policy by ***August 19*** – pension and OPEB assumptions, calculations and accounting treatment
- Senior Manager, Regulatory Finance by ***August 23*** – deferral and variance account assumptions, calculations and accounting treatment
- Director, Taxation – income taxes
- Assistant Treasurer – Treasury inputs

The sign-off will confirm that the Finance staff have reviewed the planning submissions and are in agreement with the following (as applicable) in respect of the submissions:

- Appropriateness and consistency of financial/economic assumptions
- Compliance of submissions with US Generally Accepted Accounting Principles (GAAP), including consistency of their application
- Completeness and accuracy of the financial submissions on the basis of known operational assumptions
- Basis of investment decisions identified in the plan
- Compliance of financial/economic assumptions and calculations with contractual, legal, regulatory or other requirements, and OPG governance

- Compliance with these business planning instructions, including the requirement to use the half-year rule for determining FTEs in costing planned labour (see section 3.5)
- Material asset removal costs, in-service additions, and asset retirements have been identified in the appropriate period and have been correctly classified in accordance with US GAAP
- Interest capitalized on construction and development in progress has been calculated using interest rates per the planning instructions and in accordance with US GAAP
- Planned costs have been appropriately classified as capital, OM&A or provision expenditures in the appropriate period in accordance with US GAAP
- Planned contractual milestone accruals have been budgeted in the appropriate period
- Valuation of materials and supplies inventory and related obsolescence charges are appropriate
- Valuation and depreciation/amortization of fixed and intangible assets (based on station/asset class services lives) over the planning period are appropriate in accordance with US GAAP
- Underlying assumptions and valuations for provisions included in the plan, other than for nuclear decommissioning and waste management, (e.g., First Nations, environmental, [redacted] etc) are based on measurability and probability of occurrence criteria in accordance with US GAAP
- Based on planning assumptions outlined in these instructions, assumptions underlying the obligations for nuclear decommissioning and waste management are appropriate, and the obligations would be fairly stated in accordance with US GAAP
- Planned regulatory asset and liability balances are appropriately stated in accordance with US GAAP
- Derivative financial instruments have been identified and appropriately recognized/valued in accordance with US GAAP, based on planning assumptions
- Inputs into calculations [redacted] are appropriate and consistent with costs and other planning submissions to BP&PR
- All material accounting implications of current or anticipated policy changes have been identified and included in the planning submissions
- Income and other tax calculations have been appropriately performed
- Other items included in the plan are reasonably stated, in light of planning assumptions outlined in these instructions and taking into account the risk of error, materiality, degree of judgement required, the nature of the item (recurring vs. non-recurring/unusual), and the complexity of accounting

As in prior years, the sign-off may take the form of a memorandum or e-mail addressed to Vice-President, Business Planning & Reporting and/or Director, Business Planning & Regulatory Finance.

5.7 INSTRUCTIONS FOR USE OF THE BPC BUSINESS PLANNING SYSTEM

CONTACT: KAREN MOONEY

Planning in BPC for 2017-2019 will use version W01. There is no need for multiple BPC versions this year because standard labour rates including payroll burdens are unchanged from the 2016-2018 BP, as discussed in section 5.1.2.

The BPC details required in order to consolidate information for the 2017-2019 BP include:

- Work program and project information trended on a monthly basis for 2017 and 2018 and annually for 2019
- Total labour requirements balanced to the total labour supply in BPC
- Headcount trending and resulting FTEs that reflect assumptions in line with the half-year rule requirement for regular labour outlined in section 3.5
- Realistic assumptions for project initiation and vacancy management

Final trended information is required on a monthly basis for budget year 2017 and for 2018. By end of day on ***October 28***, all trending must be completed in W01, and BUs will be locked out of BPC for the 2017-2019 business planning process. At that point, the trending by the BUs will be considered final and, for the 2017 budget year, ready for upload to the reporting systems.

By October 28, BU Controllers must ensure that the trended BPC input (BU OM&A, capital expenditures, provision expenditures, non-generation revenue as per section 5.2, and headcount) is complete and accurate, based on reasonable assumptions, and agrees to the CEO/ELT-approved resource levels.

Additionally, the following input will be reflected in BPC:

- MR&F is responsible for developing the BPC trending of labour rate variances, to be held at the corporate level
- In consultation with the responsible groups, BP&PR will develop trending for accretion expense and earnings on nuclear segregated funds, applicable centrally-held costs, and, based on in-service information provided by the BUs, depreciation & amortization expense
- Trended BPC input for generation revenue will be provided by Integrated Revenue Planning by ***November 16***, incorporating regulated revenue assumptions from BP&PR as required
- Trended BPC input for deferral and variance accounts will be provided by Regulatory Finance by ***November 16.***

5.8 BUDGETING FOR SERVICE PROVIDERS

CONTACTS: JENNY RUZ / BOSCO YUAN / MICHELLE GIRARD

OPG's cost model is a company-wide set of business rules that are the foundation of financial planning, budgeting and cost reporting, and define how OPG accounts for resources. All business planning at OPG is conducted in accordance with the single OPG cost model. Under the cost model, an organization at OPG plans for all the resources for which it is accountable, regardless of where the resources work or what they work on. This applies to labour, materials, purchased services, and other resources. The cost model also extends to projects, with project managers only budgeting for resources that are under their direct control.

Service recipients (in most cases the operating business units) are required to identify and estimate the annual resources that they expect to be supplied by other OPG organizations (in most cases Support Services) for inter-business unit work. ***The identification and communication of this information must occur during the initial phase of the planning process, with a signed agreement required between the service providers and service recipients by July 8, with a copy to respective controllership organizations.*** This will ensure that service providers' planning submissions adequately reflect the necessary resource levels (such as OM&A, capital including minor fixed assets, and provision expenditures) in accordance with the cost model.

Resources in support of the Darlington refurbishment being planned by Support Services require approval by SVP, Nuclear Projects.

Additional guidance regarding services provided by certain specific Support Services organizations is provided below. For Environment requirements, refer to section 6.4.

5.8.1 Information Technology (IT) Requirements

IT requirements should be communicated to the appropriate BU IT contact within BAS as identified below. The BAS business plan will include resources for business-related IT needs, IT projects, and IT components of business initiatives.

The following IT expenditures continue to be included in each BU business plan, rather than in the BAS business plan, as they are directly related to station process control, which is not available through existing IT commodity contracts:

- Process control hardware and software in Nuclear and RG&PM
- Engineering tools (hardware) and new software in Nuclear and RG&PM (annual maintenance for most existing software is covered by BAS)

Where a BU is requesting IT to assume budget accountability for existing items (e.g., annual maintenance contracts), a list of these items and their related costs should be provided to IT for inclusion in the BAS business plan.

If there is uncertainty as to whether or not a particular contract or a specific item is identified in the BAS business plan, one of the contacts listed below should be consulted.

- Director IT Enterprise Architecture and Customer Relationship Management (CRM) – Mike Borsch (400-8274 at Head Office)

- Nuclear CRM – Alewyn Mouton (905-623-6670 ext. 703-5476 at Darlington Energy Centre)
- RG&PM and Corporate CRM – Amir Shemranifar (400-6981 at Head Office)
- Director IT Projects – Kim Bosselle (400-5865 at Head Office)

5.8.2 Supply Chain Requirements

Supply Chain's focus is on providing cost effective acquisition and timely availability of materials and services, as well as managing the sale of nuclear isotopes and heavy water. During the planning period, Supply Chain will continue to work with Nuclear Fleet Operations, Maintenance, and Engineering to further refine and align performance measures across the groups. Supply Chain will also continue to administer, negotiate and execute contracts in support of the Darlington refurbishment, other nuclear projects, and hydroelectric development projects.

Supply Chain will require, early in the planning process, the BU demand information for materials and supplies and fleet vehicles in order to support continuing implementation of the following key strategies underlying the 2017-2019 BP:

- **Parts Availability** – Managing and organizing the acquisition and distribution activities in support of on-line and outage improvement strategies, work order readiness, vendor quality and supplier performance management, improving equipment reliability, and reducing replenishment of out-of-stock material

- **Materials and Supplies Management** – Working collaboratively with the stations and Nuclear support organizations to improve material availability via work management, on-line and outage planning, and project management processes. In addition, Supply Chain and the Nuclear business unit will work to identify materials and supplies requirements in support of the end of commercial operations at Pickering, and in support of the eventual safe storage and decommissioning of the Pickering units.

- **Strategic Sourcing** – As in the prior year, BUs are expected to identify strategic sourcing savings based on analysis of their procurement plans in consultation with Supply Chain, and to reflect these savings in their business planning submissions. Strategic sourcing savings must be separately identified in the respective BU business plan materials for CEO/ELT review.

- **Isotope and Heavy Water Sales** –Supply Chain will continue to contribute to OPG's revenue during the business planning period by marketing and managing the sale of existing product lines (Heavy water, Cobalt, Tritium, Detritiation) and pursuing new business opportunities as appropriate.

BUs should consult the following Supply Chain contacts, by service area, to identify business unit requirements:

- Supply Services Pickering – Ajay Upadhyaya (701-3890)
- Supply Services Darlington – Janet Donegan (905-623-6670 ext. 703-0111 at Darlington Energy Centre)
- Supply Services Waste/IMS – Robert De Bartolo (905-421-9494 ext 3470 at 1340 Pickering Parkway)
- Supply Services OPG Projects – Phil Reinert (905-623-6670 ext 703-1515 at Darlington Energy Centre)
- Strategic Sourcing – Iftikhar Haque (702-5023 at 889 Brock Road)
- Isotope, Heavy Water & Detritiation Services & Sales – Iftikhar Haque (702-5023 at 889 Brock Road)
- Warehouse and Logistics – Dave Hudson (704-6609 at Whitby Warehouse)

5.8.3 Real Estate & Services Requirements

Real Estate & Services requirements (e.g., new leases, lease renewals, facility enhancements/modifications, furniture, staff moves, office accommodation changes, office reconfigurations, surveys, imagery, printing, graphics, etc.) including capital and OM&A project requirements for each BU (including the Darlington refurbishment organization) are to be clearly identified to Real Estate & Services by ***July 8*** for consideration and inclusion in the 2017-2019 BP, subject to formal sign-offs on intra-business unit work discussed in section 3.1, as appropriate. Real Estate & Services will consolidate all facility costs in accordance with an overall leasing strategy, tracking costs by facility.

All real estate and services related requests received after July 8 will require signed service agreements between the service recipients and SVP Business and Administrative Services.

Consistent with OPG's centre-led model and under the OPG Organizational Authority Register, ***only*** Real Estate & Services has requisitioning authority for the acquisition, management, and disposal of real estate rights and interests, and related transactions, as well as home purchases and purchase guarantees.

Any changes or anticipated changes to the operating status of OPG's generation facilities as well as dispositions, acquisitions, and leases that could potentially have a financial impact on the property taxation and assessment of any OPG owned property should be communicated to Real Estate & Services – Property Assessment and Taxation by ***July 8***, in order to capture the corresponding impacts on property taxes in the 2017-2019 BP.

Real Estate & Services has identified the following contacts by service area:

- Real Estate Services – Ron Murphy (400-7201 at Head Office)
- Facility & Project Services – Don Seedman (400-3289 at Head Office)
- Bruce Lease Management Office – Paul Tolton (400-8051 at Head Office)
- Business Infrastructure Services – Keith Skrepnek (703-2507 at 1908 Colonel Sam Drive)
- Property Assessment and Taxation – Alim Yhap (400-4197 at Head Office)

5.8.4 Other Support Services

The PC&C organization is responsible for the following Human Resources services: Total Rewards (compensation, pension and benefits), Payroll, Talent Management, Business Change Management, Employee and Labour Relations, and field HR Business Partner support. In addition to Human Resources, PC&C is accountable for providing value added support in the areas of Learning & Development, Health & Safety and Corporate Relations & Communications.

For assistance on PC&C matters in developing the 2017-2019 BP, BUs should consult with the following contacts:

- Corporate Relations & Communications – Ted Gruetzner (400-6806 at Head Office)
- Talent Management and Business Change – Nicole Lichowit (400-3196 at Head Office)
- Total Rewards – Craig Halket (400-4400 at Head Office)
- Health, Safety & Labour Relations – Dave Milton (400-3238 at Head Office)
- Business Partners Nuclear – Connie Hergert (702-5133 at 889 Brock Road)
- Business Partners RGPM and Corporate – Darlene McVeity (405-4144 at Kipling)
- Learning & Development – Al Shiever (702-5095 at 889 Brock Road)

The Law division provides legal advice and solutions to legal issues faced by OPG. For assistance on legal matters in developing the 2017-2019 BP, the BUs should contact Brenda MacDonald (400-3603 at Head Office).

5.9 CAPITAL, OM&A AND PROVISION-FUNDED PROJECTS

CONTACT: ROBERT PRILLER

This section specifies the requirements for submission of the 2017-2019 BP capital, OM&A and provision-funded project portfolio listings and supporting Planning Business Case Summaries (BCSs). BUs are requested to provide their project information by ***August 8*** to Richard Wong in Finance – Investment Planning.

Section 5.9.1 specifies the listing requirements for the project portfolios. Section 5.9.2 provides the criteria for projects requiring Planning BCSs and the information requirements for Planning BCSs. Questions on these requirements should be directed to Robert Priller at 400-2670 or Silvester Wong at 400-2360.

5.9.1 Prioritized Project Lists

BUs are required to identify all capital, OM&A and provision-funded projects having cash flows within the business planning period. The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives, as well as efficient alignment with BU strategies, facility life cycle plans (as applicable), condition assessments, and Shareholder expectations.

The listing format and information requirements have not changed from the previous year and are provided in the ***Project Listing Template***, available in the ***Investment Planning Toolkit*** section of the Finance page on the OPG intranet. Definitions and explanations for the various fields in the template are provided in the ***Targets*** worksheet of the template. To facilitate review, consolidation and reporting, it is essential that BUs provide all information in the format specified in the listing template. It is also requested that each BU provide a description of their prioritization process. Alternative project listing formats approved for use in prior submissions (e.g. PPM) continue to be acceptable, however, any new proposed formats must be presented to Investment Planning for approval prior to the submission date.

5.9.2 Planning Business Case Summaries

BUs are required to submit Planning BCSs, or an equivalent document, for projects listed in their portfolio that are ***not fully released*** and meet the following criteria:

- Projects planned for release in 2017 with cash flows greater than or equal to $1M in 2017
- Projects planned for release in 2017, 2018, or 2019 with a total project cost greater than or equal to $5M

For the purpose of these instructions, ***not fully released*** projects are projects that satisfy any of the following criteria:

- Projects with no previous release(s)
- Projects with previous release(s) other than a full execution phase release
- Previously released projects that are forecasting significant changes in scope or cost, and are planned or expected to have a superseding execution phase release

The information requirements for Planning BCSs are specified in the ***Planning Business Case Summary form (OPG-FORM-0102)***. Additional information and explanations are provided in ***Developing and Documenting Business Cases (OPG-STD-0076)***. Both of these documents are available in the ***Investment Planning Toolkit*** on the Finance OPG web site. The above requirements include projects in support of non-generation business opportunities.

While the Planning BCS form sets out the information requirements, BUs will often have existing documents, such as an Asset Investment Steering Committee (AISC) - Part A: Issue Characterization form or a Type 1, 2, or 3 BCS, that meets the specified information requirements. When such documents are available and up-to-date, particularly with respect to project prioritization, cash flows and align with corporate strategic business objectives, they can be submitted in place of the Planning BCS.

All Planning BCSs should be reviewed and signed-off by the appropriate project sponsor (e.g., Asset Manager, Engineering Director, etc.) and the local Controller.

5.9.3 BCS Preparation Assistance

For assistance with BCS preparation and project grouping, please contact your local Controller or either Robert Priller at 400-2670 or Silvester Wong at 400-2360 of Investment Planning.

6.0 OTHER PLANNING REQUIREMENTS

6.1 BUSINESS PLAN RISKS

CONTACT: KRIS PROBODIAK

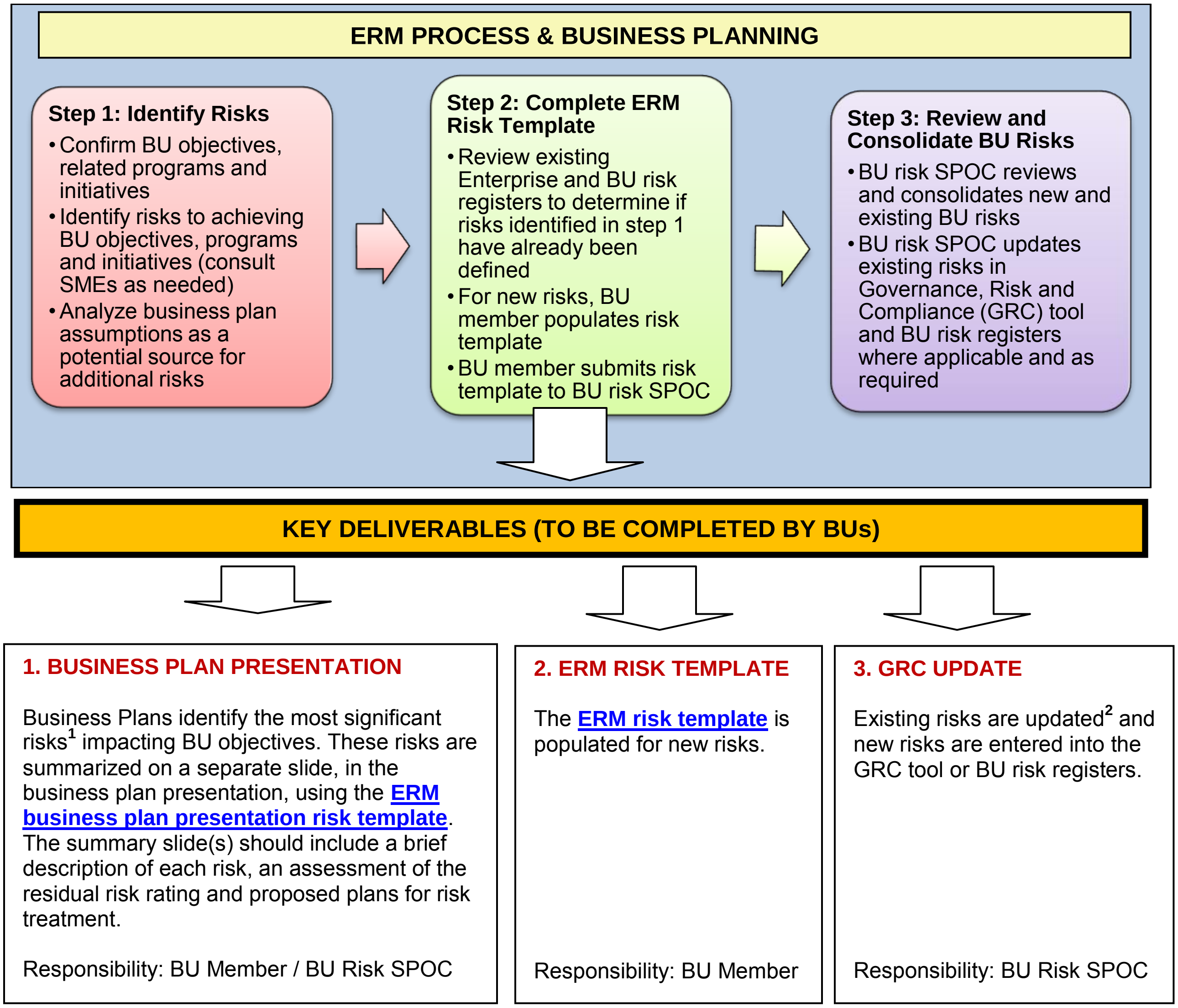
6.1.1 Enterprise Risk Management (ERM) Process

The ERM framework provides guidance for systematic organization-wide risk management, which includes identifying, assessing, prioritizing, treating, monitoring and communicating risks to the achievement of OPG's strategic imperatives and BU objectives.

As part of the business planning process, each BU must identify known risks that could impact the achievement of BU objectives, programs, and/or initiatives over the 2017-2019 planning horizon. This includes the development of risk treatment plans that help mitigate identified risks, which are funded through the business plan. Longer term strategic risks, spanning the post-2019 planning period, should also be discussed with the ERM group to ensure that they continue to be assessed as part of the integrated ERM process.

6.1.2 Deliverables

The business planning deliverables are detailed in the following schematic:



[1] BU risk SPOCs should ensure all ***reportable*** enterprise risks (at a minimum) are incorporated in the business plan materials. ***Reportable*** risks are those with a residual risk rating greater than or equal to 30 using the ERM risk rating criteria. See **OPG-PROC-0004: Enterprise Risk Management Reporting Procedure** for further information on the ERM process.

[2] Existing risks should be updated based on any plan-over-plan changes to the business plan assumptions. Action plans for addressing risks should be updated with target completion dates. Risk treatment plans should be integrated within the plans, programs and processes with which they are associated.

For further details, please visit the **ERM Website** (on PowerNet under Business Functions > Ethics, Law, Regulation, Risk & Strategy > Risk) and the **ERM Information Page** for business planning risk assessment requirements.

6.1.3 ERM Risk Reporting Timeline

Enterprise-level risks are explicitly reviewed with accountable organizations as a key component of the quarterly ERM reporting cycle. This ensures that risk management is used to inform decision-making while also reporting key risks to the Executive Risk Committee and the OPG Board of Directors. As such, the major risks impacting Business Unit objectives, which are included in the business plans, should flow through the regular quarterly ERM reporting cycle. An **ERM SPOC** should be contacted for any questions about the ERM risk reporting process or timeline.

6.1.4 Risks Impacting Business Continuity and Emergency Management

Risk identification should ensure that all hazards to OPG are considered. A list of these hazards can be found in **OPG-PROG-0004** (Enterprise Risk Management, Appendix A, page 14).

6.2 CORPORATE SAFETY

CONTACT: GREG JACKSON

With safety as a core value, OPG is committed to safety excellence, sustaining a strong safety culture and continuous improvement in pursuing the goal of zero injuries. The BUs are expected to program accordingly. Questions regarding planning for the below initiatives should be directed to Greg Jackson at 905-576-6959 ext. 3339.

The BUs are encouraged, through the operation of the OPG Health and Safety Management System to identify priorities and to set objectives that will support achievement of the safety objectives. A key focus at the corporate level will be on being alert for one's individual safety and the safety of others during routine activities as well as maintaining focus and situational awareness. The BUs are encouraged to examine their High Maximum Reasonable for Potential Harm (MRPH) incident history and consider what actions/programming may be required to mitigate such events.

Safety incidents resulting from contractor work performance continue to be rated as a high risk on the Enterprise Risk Registry, and in particular, in the Nuclear business unit. The health and safety division along with the Nuclear Projects organization will continue to implement contractor management and contractor oversight governance expected to improve controls on contractor work performance and yield improved safety performance results.

It is anticipated that, over the business planning period, the evaluation and determination of measures to control exposure to radon gas will be required, the extent to which is unclear at this time. In 2014, a private member's bill, Bill 11, was introduced in the Ontario legislature to amend the Ontario Building Code to require measures to control radon gas exposure to building occupants. OPG will be undertaking a study to assess radon gas exposure levels in facilities across OPG and identify what, if any, measures may be required to mitigate exposures to acceptable levels. Nuclear Health Physics should include costs in their plan to cover the costs of this evaluation.

6.3 INDIGENOUS RELATIONS INITIATIVES

CONTACT: IAN JACOBSEN

OPG recognizes the importance of continuing to strengthen relationships with the Indigenous Peoples in Ontario. As set out in ***OPG-STD-0087***, ***Management of First Nations and Métis Relations***, operating BUs and support services functions' plans should be developed with a view of implementing the requirements of ***OPG-POL-0027***, ***First Nations and Métis Relations Policy***, by including appropriate program activities and associated costs. All operating BUs and other line organizations that have regular contact with indigenous communities are required to develop programs in support of this Policy and include relevant resource requirements in their business plans. In addition, all BUs that have planned for resources related to indigenous communities are required to provide specific program details to Indigenous Relations by ***August 19***. For further guidance on the information requirements, please contact Ian Jacobsen at 400-3770.

6.4 ENVIRONMENTAL PLANNING REQUIREMENTS

CONTACTS: BARB MEDEIROS / HEATHER BROWN

OPG is committed to maintaining high standards of environmental stewardship. The BUs are expected to reflect this commitment in their business plans.

The environmental component of OPG's business plan is centred on implementing programs to meet the requirements of the ***Environmental Policy (OPG-POL-0021)***, including the following:

- Maintaining a single OPG Environmental Management System (EMS) certified to ISO 14001:2004 standard;
- Effectively managing OPG's Significant Environmental Aspects; and
- Considering changes in environmental legislation.

As in previous years, environment programs or work should be identified as part of this year's business planning and, consistent with partnering agreements, the associated budgets should reside with the group that has accountability for the work. Budgeting decisions should be made in collaboration and with mutual agreement between the BUs and Legal, Ethics & Compliance – Environment. Specifically with respect to onsite biodiversity, the budget will be held by Legal, Ethics & Compliance – Environment.

Maintaining a Single OPG Environmental Management System

BUs should not budget for maintenance of a local ISO 14001 EMS as this work is carried out by Environment. BUs should budget for maintenance of those components of the EMS that are within their accountabilities, particularly operational control and emergency preparedness and response.

Where changing local conditions may warrant additional third-party self-assessment beyond the scheduled audits for maintenance of ISO 14001 registration, BUs should identify and reach agreement with Environment on these circumstances. The purchased service costs for these additional assessments will be included in the Environment Business Plan.

Significant Environmental Aspects

BUs are asked to review the applicable ***Environmental Programs Summary Documents***, available from the ***Environment Intranet Site*** for each of OPG's Significant Environmental Aspects, as described in the updated table below.

BUs should budget to meet these program requirements. In order to ensure good management of environmental aspects, including timely receipt of any required environmental approvals, BUs are asked to identify the following in their business plans:

- Any new or revised programs, projects, or activities that will result in a change in OPG's management of a Significant Environmental Aspect or the environmental impact of a Significant Environmental Aspect. The change can be an improvement, such as reduced emissions, or reduced costs of managing the Significant Environmental Aspect; or
- Any new or revised programs, projects or activities that introduce a new environmental aspect, such as a new waste stream or effluent.

Significant Environmental Aspect	Business Unit			
	Nuclear			
	Operations	Refurbishment	RG&PM	BAS
Carbon 14 emissions to air	✓			
Chemical emissions to water	✓	✓	✓	
Displacement of fossil fuels	✓		✓	
Fish impingement/entrainment	✓		✓	
Wildlife habitat (enhancement or disruption)	✓	✓	✓	✓
Spills	✓	✓	✓	✓
Tritium emissions	✓	✓		
Thermal effluent emissions	✓		✓	
Water flows and level changes			✓	
Waste generation: low and intermediate level radioactive waste	✓	✓		

Planning for Deadlines in Existing Environmental Legislation

Phase-out of Hydrochlorofluorocarbon (HCFC) Refrigerants

BUs need to plan to fulfil regulatory requirements for the phase out of HCFC refrigerants by 2020 in accordance with the Ozone-depleting Substances Regulations under the *Canadian Environmental Protection Act.* BUs should consider, where applicable, establishing a systematic process to identify and replace HCFC refrigerants targeted for phase-out.

Phase-out of Polychlorinated Biphenyls (PCBs)

BUs need to plan to fulfil the phase-out provisions of the PCB Regulations (2008). The BUs should consider, where applicable, establishing a systematic process to:

- identify and replace electrical oil filled equipment (transformers, bushings, instrument transformers, pole-top transformers, etc.) containing PCB in a concentration of 50 ppm or greater by 2025;
- replace electrical oil filled equipment (transformers, bushings, instrument transformers, pole-top transformers, etc.) by 2025, where PCB concentration cannot be determined;
- identify fluorescent light ballasts remaining in service that may be PCB contaminated; and
- remove and destroy PCB contaminated fluorescent light ballasts when they are taken out of service or by 2025.

Air Emission Standards

BUs need to plan to adhere to the staged phase-out of the air dispersion models used to assess compliance with the air standards of O. Reg. 419/05 under the Ontario *Environmental Protection Act*. The BUs should consider, where applicable, establishing a systematic process to ensure that by February 1, 2020, all air discharges comply with the Schedule 3 Air Standards.

No other legislative changes currently require consideration in the 2017-2019 BP.

New Environmental Legislation and Programs

Ontario Cap-and-Trade Program - Climate Change Mitigation and Low-Carbon Economy Act

Ontario has passed the Climate Change Mitigation and Low-Carbon Economy Act and associated regulations to implement a Cap and Trade Program for greenhouse gas emissions. The compliance period begins January 1, 2017. Since the point-of-regulation is the fuel suppliers, OPG will not have compliance obligations for the greenhouse gas emissions from operations, other than through reporting. However, OPG will have compliance obligations for the greenhouse gas emissions associated with arranged electricity imports based on Default Emission Factors for the exporting jurisdiction specified by the Ontario Ministry of Environment and Climate Change. Accordingly, RG&PM should plan for increased fuel prices, namely fuel oil that is directly imported from Quebec for the [redacted] as well as fulfilment of compliance obligations and associated costs for imported electricity.

Ontario's Climate Change Strategy

Ontario has published a Climate Change Strategy, which includes plans to reduce greenhouse gas in key sectors. Environment will budget for analysis of the Climate Change Strategy and propose any program(s), in consultation with the BUs, that may present opportunities for OPG.

Environmental Targets

Environmental targets for the 2017-2019 BP period will be established by Environment for Nuclear, RG&PM and BAS, in consultation and agreement with the BUs, consistent with partnering agreements. These targets would be reflected by the BUs in their respective business plans.

Board Staff Interrogatory #4

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

Interrogatory

Reference:

Ref: Exh A1-6-1
Ref: Exh C2-1-1 Table 1

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

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

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

Response

The reference cited in this interrogatory cites section 6(2)8 of O. Reg. 53/05 which requires the OEB to accept the revenue requirement impact of an aspect of OPG's revenue requirement. The interrogatory requests OPG to cite all aspects of the 2017 revenue requirement that are subject to specific rules of O. Reg. 53/05 and to respond in a similar format. The format provides the specific revenue requirement impact that the OEB must accept. There is only one other 2017 revenue requirement impact that the OEB must accept that can be provided in a similar format. Section 6(2)9 requires that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear stations. These costs are forecast at $317.3M in 2017 as provided in Ex. G2-2-1 Table 1, line 8, col. (e).

There are other aspects of the 2017 nuclear revenue requirement that are subject to rules of O. Reg. 53/05 that do not require the OEB to accept an item of revenue requirement and therefore cannot be reported in a similar format to that reflected in the reference to the interrogatory. Section 6(2)4 and 6(2)4.1 require the OEB to ensure recovery of certain capital and non-capital costs and firm financial commitments. Section 6(2)4 addresses Darlington Refurbishment Program and capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a prescribed facility, section 6(2)4.1 addresses development of proposed new nuclear generation facilities. These costs are subject to variance and deferral account treatment, will have a reference amount set by the OEB based on the 2017 revenue requirement, and are subject to a prudence review by the OEB.

Board Staff Interrogatory #99

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

Interrogatory

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

Please file the nuclear business plan.

Response

OPG has one business plan approved by OPG's Board of Directors (Ex. A2-2-1, Attachment 1). This comprehensive document includes all business areas within OPG. Appendix 5 to the 2016-2018 OPG Business Plan identifies the key financial and operational targets for the Nuclear business as well as the key initiatives being undertaken by OPG as part of continuous improvement within Nuclear. These are the initiatives referred to in the excerpt from Ex. A1-3-2 referenced in this interrogatory.

The OPG Board did not approve a separate business plan for the Nuclear business or any other business unit of OPG in the 2016-2018 planning process. The various planning activities, their costs and the resulting deliverables from Nuclear are disclosed in the body of the 2016-2018 OPG Business Plan and in Appendix 5.

AMPCO Interrogatory #1

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

Interrogatory

Reference:
Ref: A2-2-1

a) Page 3: Please confirm the annual staff reductions over the past 5 years.

b) Page 4: Please provide the specific business areas and types of positions where critical skill shortages/gaps is being experienced by OPG.

c) Page 4: Please discuss the potential impacts in the test period of the new Ontario Nuclear Funds Agreement (ONFA) Reference Plan in 2017.

d) Given that OPG has filed a 5-year rate application with Payment Amounts for 2017 to 2021, please explain why OPG did not elect to prepare a five-year business plan.

e) Page 5: Please provide OPG's confidence level in the 2019-2021 projections by year.

f) Page 7: Please provide an update on the Province's concurrence on the 2016-2018 Business Plan.

g) Please provide the Terms of Reference for all studies filed in this application that are not already in evidence.

Response

a) Please see Table 1 below.

	Table 1: Total OPG Year-End Headcount from Ongoing Operations					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**
Headcount	11,686	11,215	10,664	10,085	9,489	9,010

b) Please see L-06.6-1 Staff-138 part (b), L-06.6-13 PWU-11 part (a), and L-06.6 -2 AMPCO-128. Furthermore within OPG's operations business there is shortages in nuclear authorized, engineering, mechanical and control operations specialist roles. OPG anticipates significant attrition due to retirements in its management group positions over the next several years. In anticipation of this attrition, a number of actions have been undertaken including: targeted development plans for successors to key roles, identification of talent attraction strategies for roles that could be sourced externally, and continued delivery of high potential develop programs to accelerate readiness of individuals in the leadership pipeline.

c) Please see Ex. L-8.2-1 Staff-208.

d) Recognizing the OEB's expectation that Custom IR applications span five years, and consistent with the O. Reg. 53/05 requirement for the OEB to determine the approved and deferred nuclear revenue requirements under rate smoothing on a five-year basis, OPG extended its 2016-2018 Business Plan to include information for the full five years of the IR Term. In OPG's view, this provides an appropriate and consistent basis for the OEB to determine revenue requirements and payment amounts in this application. As discussed at Ex. A2-2-1, p. 2, lines 16-22, this five-year information was developed on the same basis and through a consistent process, including the application of consistent inputs and planning assumptions, utilizing the same corporate planning tool, and generating the same key financial outputs.

e) OPG's 2016-2018 Business Plan, including the 2019-2021 financial projection, is the result of a comprehensive, structured corporate-wide business planning process (see part (d)). While significant risks and uncertainties are inherent in a set of forward looking information for a company of OPG's size and complexity (for example, see Ex. A2-2-1 Att.1, pp. 19-20), OPG has a high level of confidence in the quality and rigor of the planning information for each of the years in the 2017-2021 period. As with most forecasts, the band of planning uncertainty inherently increases in the later years of the planning period.

f) A concurrence letter for the 2016-2018 Business Plan has not yet been received from the Province.

g) OPG interprets part (g) as referring to all studies that were prepared by third parties in direct support of the Application. Attachment 1 lists all such studies, along with the location of the associated Terms of Reference which fall into three groups:
    1) **Filed in Initial Evidence**: In such instances, the study was included in the pre-filed evidence, and the Terms of Reference were provided as an attachment to the study.
    2) **Filed as Interrogatory Response**: If the Terms of Reference have been provided in response to another interrogatory, the response is identified.
    3) **Filed as attachment to this Interrogatory**: Terms of Reference that have not been provided in the pre-filed evidence or in response to another interrogatory are attached to this response (Attachments 2 (confidential), 3 and 4).

Title of Study	Study Location	Terms of Reference Location
Empirical Analysis Of Total Factor Productivity Trends In The North American Hydroelectric Generation Industry. London Economics International LLC. February 19, 2016	Ex. A1-3-2, Attachment 1	Ex. L-11.1-5-CCC-44, Attachment 1
Hydro Benchmarking Study. Navigant Consulting, Inc. August 17, 2015	Ex. A1-3-2, Attachment 2	Ex. L-11.1-5-CCC-45, Attachment 1
Inflation Factor Analysis for OPG's Regulated Hydroelectric IRM. London Economics International LLC. December 17, 2014	Ex. A1-3-2, Attachment 3	Ex. L-11.1-5-CCC-44, Attachment 1
Common Equity Ratio For OPG's Regulated Generation. Concentric Energy Advisors	Ex. C1-1-1, Attachment 1	Ex. C1-1-1, Attachment 2
Assessment of Commercial Strategies Developed for the Overall Darlington Refurbishment Project and the Retube & Feeder Replacement Work Package. Concentric Energy Advisors. September, 2013	Ex. D2-2-2, Attachment 1	EB-2013-0321, Ex. D2-2-1, Attachment 7
Updated Assessment of Commercial Strategies Developed for the Darlington Refurbishment Program Retube & Feeder Replacement Work Package. Concentric Energy Advisors. July, 2016	Ex. D2-2-11, Attachment 1	Ex. D2-2-11, Attachment 2
Testimony of Dr. Patricia D. Galloway. Pegasus Global Holdings, Inc. July, 2016	Ex. D2-2-11, Attachment 3	Ex. D2-2-11, Attachment 4
2014 Nuclear Staffing Benchmarking Analysis. Goodnight Consulting. December 22, 2014	Ex. F2-1-1, Attachment 2	Ex. L-1.2-2-AMPCO-1, Attachment 2
ScottMadden Evaluation of OPG Nuclear Benchmarking. Scott Madden Management Consultants. 2015	Ex. F2-1-1, Attachment 3	Ex. L-1.2-2-AMPCO-1, Attachments 3A and 3B
Benchmarking Study of OPG's Corporate Support Functions and Costs. The Hackett Group. April, 2016	Ex. F3-1-1, Attachment 1	Ex. L-1.2-2-AMPCO-1, Attachment 4
Total Compensation Benchmarking Study. Willis Towers Watson. April 22, 2016	Ex. F4-3-1, Attachment 2	Ex. L-6.6-1-Staff-149, Attachment 1
Comparison of Salary Schedules for Society and PWU Roles. Willis Towers Watson. April 25, 2016	Ex. F4-3-1, Attachment 3	Ex. L-6.6-1-Staff-149, Attachment 1

SCHEDULE A – STATEMENT OF WORK

Nuclear Staffing Study
Table of Contents

1. INTRODUCTION

1.1. Background of the Project

As part of its ongoing benchmarking process, OPG will be undertaking a nuclear staffing study. The primary objective of the project will be to compare OPG nuclear staffing levels against other nuclear operators; identify the source of any significant differences in staffing levels; and analyze the nature of these differences year over year.

This initiative is being undertaken in part as a result of direction and recommendations provided by the Auditor General of Ontario. For further reference, see the below link: Chapter 3, Section 3.05 Ontario Power Generation Human Resources.

http://www.auditor.on.ca/en/reports_en/en13/305en13.pdf

1.2. Purpose of the Project

For the next three year, to benchmark OPG nuclear staffing levels against other nuclear operators; identify the source of any significant differences in staffing levels; and analyze the nature of these differences. Excluded from scope will be major project staffing (i.e. Darlington Refurbishment)

By reference to OPG's current business plan, the consultant should also comment on OPG's plans with respect to staffing levels.

1.3. Target Start/Completion Date of the Project

In 2014, the target start date is the week of April 7, 2014. The completion of the final report is targeted by the end of May 2014, as it is required for the 2015-2017 business plan submission.

For 2015 and 2016, if consultant is required to be engaged, OPG will define the scope of work, by end of first quarter of that year.

Considering OPG's regulated structure with the Ontario Energy Board (OEB), the consultant may be required to testify to the report at future OEB hearings and respond to interrogatories and undertakings, etc.

1.4. Pricing of the Project

For pricing, refer to Schedule B, Pricing.

2. Implementation Strategy

The consultant's implementation strategy should include a kick off session, derivation and analysis of staff levels, and interviews with OPG subject matter experts. OPG requires interim progress updates followed by a final report of the methodology employed, analysis performed and findings, for presentation to OPG management.

3. Scope of Work

The following process/scope of work is to be undertaken by the consultant to examine staffing levels. As labour costs are the most significant component of OPG's cost of service, the process outlined below would also require the consultant to directly address, by reference to staffing, the major cost differences between CANDU and PWR/BWR.

- Access potential data sources (e.g. WANO (World Association of Nuclear Operators), Electric Utility Cost Group (EUCG), consultant proprietary databases, COG), and compile comparison analysis of OPG staffing with that of industry peers. The comparison should be by job function and organizational structure. Separate peer group comparisons (e.g. Canadian CANDU (CANada Deuterium Uranium), All CANDU, CANDU plus Pressurized water reactor (PWR) / Boiling water reactor (BWR)) should be provided, if possible. Nuclear staffing levels analyzed should include regular company employees, full time equivalents (FTEs) of temporary employees, contractors and contracted services.
- Identify relevant factors which need to be taken into account in making comparative assessments of staffing levels. In particular, in correlating OPG staffing with US plants, the assessment should take into account current OPG staffing levels required to pursue the various initiatives underway at OPG to improve reliability through improved plant material condition that will allow OPG to narrow the reliability performance gap with its peers. The report should assess OPG levels of contracted services and external contractor against peers to ensure accurate comparison. A detailed examination of staffing levels and required level of work effort within an OPG organizational unit (e.g. engineering) may be feasible and would be an option to be pursued with the consultant.
- Analyze OPG staffing levels for factors which are beyond OPG's control, which are not actionable or a significant constraint (e.g. technological differences between CANDU and PWR/BWR, geographic differences, level of unionization, hours of work, economies of scale in U.S nuclear industry versus Canada, different nuclear regulatory requirements, etc).
- Review for reasonableness, achievability and timeliness the staffing performance targets and implementation plans under development as part of OPG's business planning process.

4. Term

This Statement of Work has a three (3) year term commencing as of the Effective Date of the Modified A-29 Contract and ending March 31, 2017, subject to early termination in accordance with sections 23 and 26. OPG, at its sole discretion may extend the term of this Statement of Work, for two (2) consecutive renewal terms of one (1) year each based on the same terms and conditions in the original Term.

5. Deliverables

The consultant will deliver a report that:

- provides an analysis of OPG staffing relative to industry peers,
- highlights the differences in staff levels between OPG and the industry benchmarks, and explain the factors contributing to the differences,
- review preliminary short term and long term staff targets for reasonableness, achievability and timeliness.

The consultant's report may be included in the next filing of an Ontario Energy Board (OEB) application for new rates.

6. Responsibilities

6.1. Consultants Responsibilities

The consultant may be required to testify to the report at a future OEB hearing, respond to interrogatories and undertakings, etc.

6.2. OPG's Responsibilities

OPG to provide office space, computer access and limited administrative support. OPG has assigned a project manager to this project, which will co-ordinate access to subject matter expert assistance as required.

OPG will provide reference material, as requested. OPG is a member of Electric Utility Cost Group (EUCG) and World Association of Nuclear Operators (WANO).

SCHEDULE B – PRICING

Nuclear Staffing Study

2014 RATES:
Effective April 1, 2014 to March 31, 2015

Name of Candidate	Role	Hourly Rate	Expected Hours of Work	Total Amount
Charles Goodnight	Engagement Director	[redacted]		
Peter Schneider	Project Manager			
Ed Scholz	Sr. Nuclear Consultant			
Teb Bowman	Sr. Nuclear Consultant			
Dan Scholz	Nuclear Consultant			
Austin Goodnight	Consultant			
Emily Bylund	Project Support			
Paris Goodnight	Administrative Oversight			
TOTAL				

2015 RATES:
Effective April 1, 2015 to March 31, 2016

Name of Candidate	Role	Hourly Rate	Expected Hours of Work	Total Amount
Charles Goodnight	Engagement Director	[redacted]		
Peter Schneider	Project Manager			
Ed Scholz	Sr. Nuclear Consultant			
Teb Bowman	Sr. Nuclear Consultant			
Dan Scholz	Nuclear Consultant			
Austin Goodnight	Consultant			
Emily Bylund	Project Support			
Paris Goodnight	Administrative Oversight			

2016 RATES:
Effective April 1, 2016 to March 31, 2017

Name of Candidate	Role	Hourly Rate	Expected Hours of Work	Total Amount
Charles Goodnight	Engagement Director	[redacted]		

Peter Schneider	Project Manager	[redacted]
Ed Scholz	Sr. Nuclear Consultant	
Teb Bowman	Sr. Nuclear Consultant	
Dan Scholz	Nuclear Consultant	
Austin Goodnight	Consultant	
Emily Bylund	Project Support	
Paris Goodnight	Administrative Oversight	

All rates in Canadian dollars.

No Additional Administration Fees shall apply.

Travel and Living will be billed separately according to OPG's Standard Form, Business Expense Schedule.

If necessary, with OPG's approval, The Name of the Candidate may change but the Role and the Hourly Rate as listed in the chart above will remain as the maximum Hourly Rate OPG will pay.

ONTARIOPOWER GENERATION

Records File Information:
Retain in the Contract File
for T-06, SUP-0002

Internal Use Only

N-FORM-10029-R011*

Services - Request for Purchasing

Prepared by:	John Blazanin	Telephone:	(905) 839-6746, ext. 4215
Title:	Director, Controllership	Department:	Nuclear Finance
Site/Location:	889 Brock Road, P82-3	☒	New Contract **(Complete Sections 1-6 and Sections 7 and 8 if applicable)**
		☐	Instruction Notice to existing Contract **Note:** Original contract value to be identified below. Existing PO #: ☐ No change to QA/PB requirements from existing contract **(If no change to QA/PB requirements, only complete Sections 1,2,5,6 and Sections 7,8 if applicable)**
Project Title:	Staff Benchmark Study	☐	Supports a Nuclear Operations Portfolio Project **(Complete Sections 1-6 and Sections 7 and 8 if applicable)**

Estimated Value (A):	<100K	Estimated Contingency Amount (B):		Previous Contract Value (if applicable) (C):		Total Requisition Amount (A + B) + C (if applicable):	<100K

Non-Consulting Services ☐ Staff Augmentation ☐ Consulting Services ☒ Former Employee of OPG? ☐

Has the PSA or CPAA been approved? Yes ☐ No ☐ N/A ☒

Section 1: Scope / Statement of Work

☒ **Scope of Work / Description of Duties**

Identify key milestones, deliverables, expected results, description of duties, location, schedule, etc. as appropriate.

Since 2009 it is possible that some of the standard industry metrics identified for benchmarking the OPG nuclear fleet may have changed in definition and calculation. In addition, the appropriate peer groups for comparison may also have changed. In an effort to ensure OPG's benchmarking and target setting processes are still responsive to the direction from the OEB, OPG has requested an independent third-party evaluation of benchmarking in OPG Nuclear. Specifically, ScottMadden will evaluate:

I. The current process for OPG Nuclear Benchmarking (as defined and recently performed in support of the 2015-17 business planning cycle), including:

a. Identification of key performance metrics to be benchmarked
b. Selection of companies to be included in the peer panels
c. Preparation of supporting analyses and displays of data
d. Use of the benchmarks in the business planning cycle

II. The proposed methodology used by OPG to derive Darlington targets, reflecting the impact of the Darlington Refurbishment project, for its 20 benchmarking indicators in 2016 and 2017.In support of annual benchmarking efforts (as defined and recently performed in support of the 2015-17 business planning cycle, including:

☐ **Augmented Staff**

Provide justification/rational for use of augmented staff.

*Associated with N-PROC-MM-0001, Requisition of Services

Services - Request for Purchasing

☐ **Construction Services / Statement of Work**

Include completed N-FORM-11160: BTU Contract Statement of Work. If the scope of work document is security protected, please include only the identification reference and date when the scope of work document was approved.

Need Date	2015-03-02 (yyyy-mm-dd)	End Date	2015-05-30 (yyyy-mm-dd)

Services - Request for Purchasing

Section 2: Recommended Sourcing Strategy		
☐ Utilize Existing Master Service Agreement	☐ Utilize Competitive Bid Process	☒ Utilize Single Source Strategy

Note: Refer to OPG-PROC-0058 for details on sourcing strategy and any restrictions.

Has Supply Chain been contacted for recommended Sourcing Strategy? ☒ Y / ☐ N

Note: Please identify the following information:

- Evaluation/Selection Criteria (if a single source, attach OPG-FORM-0003: Single/Sole Source Justification).
- For Staff Augmentation: Qualifications / Certifications Required / Skill Set / OPG Stratum Level (MP2, MP3, MP4, etc).

Reference Single Source Justification attached.

Section 3: Quality Assurance Program

Select QA Program Used:

☐ OPGN QA Program ☒ QA Program Not Required

☐ Supplier's QA Program (*select from box below*)

Select the Appropriate Quality Assurance Program(s)

☐ ISO/IEC – 17025 (Calibration or Testing Services)	☐ Calibration Services per N-INS-01516-10008	☐ Testing Services per N-INS-08173-10032	☐ Software Quality Assurance per N-PROC-MP-0049

☐ CSA N286-05 Procurement (applicable elements)

☐ Z299.1	☐ CSA N286-05 Design (applicable elements)	☐ CSA N286.1 (applicable elements)
☐ Z299.2	☐ CSA N286-05 Construction (applicable elements)	☐ CSA N286.2 (applicable elements)
☐ Z299.3	☐ CSA N286.7 Computer Programs	☐ CSA N286.3 (applicable elements)
☐ Z299.4	**Note:** The selection of any of the above CSA N286 programs must be accompanied by a Z299 selection.	

Other

Section 4: Pressure Boundary Quality Requirements

Does the Scope of Work contain Pressure Boundary activities? ☐ Yes ☒ No *(if yes select appropriate requirements below)*	Which Certificate of Authorization (C of A) will be used? OPG C of A ☐ or Contractor's C of A ☐

Select the appropriate Pressure Boundary quality requirements.

☐ CSA B51 Compliant Program

☐ CSA N285 / ASME III CL1,1C ☐ CL2/2C ☐ CL3/3C (NCA 4000)

☐ CSA N285 / ASME III Material (NCA 3800)

☐ CSA N285 / ASME III CLMC / CL4 (NCA 4000)

☐ Testing Services per OPG N-INS-08173-10032

Other

Verified by Engineering Delegate:

Print Name | Signature | Date: YYYY-MM-DD

Approved by Section Manager, Engineering:

Print Name | Signature | Date: YYYY-MM-DD

Section 5: Material Request

Charge to (44 digit code):

	Resp Centre	FAC	Resource Type	Service Unit	WPS	Project Number	Activity Field	SCI	Unit	Client	Local Field
# digits	4	5	3	4	4	5	3	5	2	4	5
	1028	62000	310	1028	7207	00000	000	00000	00	0000	00000

Identify Material Request Number or Attach copy of FIN-FORM-CM-016: Contract Change Authorization:

Note: For Staff Augmentation, Material Request is prepared by Supply Chain.

Verified

I certify that the above charge number is correct and the Asset Suite MR contains the correct number.

☐ Project, Project CSA

☒ Base, Finance

George Turner, Finance Controller [signature]
(Print Name and Signature)

Date Verified: 2015-03-03
(YYYY-MM-DD)

Section 6: Required Approvals

Prepared by:
(Print Name and Title)

Signature:

Date Submitted:
(YYYY-MM-DD) Location: Tel:

Reviewed by Contract Owner: John Blazanin, Director Controllership, Nuclear Finance
(Print Name and Title)

Signature: [signature]

Date Submitted: 2015-03-03
(YYYY-MM-DD) Location: P82-3 Tel: 702-4215

Services - Request for Purchasing

Note: Not required for requisitions less than $5 Million where the scope and budget is covered by an approved Nuclear Operations Portfolio Project BCS.

Reviewed by Local Finance: John Blazanin, Director Controllership, Nuclear Finance
(Print Name and Title)

Signature:

Date Submitted: 2015-03-03
(YYYY-MM-DD) Location: Tel: 702-4215

I hereby certify the scope and budget are within an approved Project BCS or Business Plan.

Approved by the Requisitioning Line Authority as per the OAR: Glenn Jager, Chief Nuclear Officer
(Print Name and Title)
OAR Authority Level:

Signature:

Date Submitted: 2015-03-05
(YYYY-MM-DD) Location: P82-6 Tel: 702-5294

Additional OAR Approval, (if required):
(Print Name and Title)
OAR Authority Level:

Signature:

Date Submitted:
(YYYY-MM-DD) Location: Tel:

Additional OAR Approval, (if required):
(Print Name and Title)
OAR Authority Level:

Signature:

Date Submitted:
(YYYY-MM-DD) Location: Tel:

Additional OAR Approval, (if required):
(Print Name and Title)
OAR Authority Level:

Signature:

Date Submitted:
(YYYY-MM-DD) Location: Tel:

Section 7: Exception Approvals (Refer to OPG-PROC-0058)			
VP of Requisitioning Department:	(Print Name and Title)		OAR Authority Level:
Signature:			
Date Submitted:		Location:	Tel:
Vice-President – Nuclear Human Resources and Employee Safety (if required)	(Print Name)		
Signature:			
Date Submitted:		Location:	Tel:
Vice-President, Nuclear Finance Approval (if required)	(Print Name)		
Signature:			
Date Submitted:		Location:	Tel:
Vice-President, Strategic Supply Chain, Quality and Planning Approval (if required)	(Print Name)		
Signature:			
Date Submitted:		Location:	Tel:
Section 8: Reviews			
Supply Chain Reviewer:	(Print Name and Title)		Date Reviewed:
Signature:			

ONTARIOPOWER GENERATION

Records File Information:
Retain in Contract File for T-06
after completion/settlement,
SUP-0002

Internal Use Only

OPG-FORM-0003-R004*

Single Source / Sole Source Justification

Subject:	Description of Item and/or Service: In 2009, OPG initiated a competitive bidding process to select an external vendor that could assist OPG in formally benchmarking its nuclear financial and non-financial performance. ScottMadden was the successful proponent selected and retained by OPG under Purchase Order # 108353. The objective of the exercise in 2009 was to develop a benchmark process that would identify, clarify and confirm performance gaps and to identify potential cost and performance improvement areas for inclusion in that year's nuclear business plan. This initiative was undertaken consistent with shareholder mandate and pursuant to direction from the Ontario Energy Board (OEB). Since this time, annual benchmarking has been a standard part of OPG Nuclear's annual business planning process. OPG has continued to publish annual benchmarking results, comparing OPG to the nuclear industry in terms of financial and non-financial performance metrics. Results are then used to inform target setting for the business planning process. Since 2009 some of the standard industry metrics identified for benchmarking performance of the OPG nuclear fleet have changed in definition and calculation and OPG has maintained changes consistent with the industry. However, there is the potential for other changes including appropriate peer groups comparisons. In an effort to ensure OPG's benchmarking and target setting processes are still responsive to the direction from the OEB, ScottMadden's services are required to ensure the benchmarking process is relevant when compared to current industry standards.
Vendor Name:	Scott Madden
Total Estimated Spend:	$ 92,903
Background:	Provide a brief description and estimated value of the project. Identify Supplier and Catalog Identification Number (CAT ID) or Material Code as appropriate.

Specifically, ScottMadden will evaluate:

I. The current process for OPG Nuclear Benchmarking (as defined and recently performed in support of the 2015-17 business planning cycle), including:

a. Identification of key performance metrics to be benchmarked
b. Selection of companies to be included in the peer panels
c. Preparation of supporting analyses and displays of data
d. Use of the benchmarks in the business planning cycle

II. The proposed methodology used by OPG to derive Darlington targets, reflecting the impact of the Darlington Refurbishment project, for its 20 benchmarking indicators in 2016 and 2017.

Justification is being prepared for:

Note: Select appropriate box for both (a) and (b) below.

(a) ☒ Single Source ☐ Sole Source

(b) ☒ Consulting Services ☐ Non-Consulting Services ☐ Items ☐ Staff Augmentation

To your knowledge, has Ontario Power Generation (OPG) awarded a Single Source / Sole Source contract to this vendor previously? ☐ Yes ☒ No

*Associated with OPG-PROC-0058, Procurement Activities

Select the allowable exception that best applies: (Refer to OPG-PROC-0058, Appendix B for additional details).	
(1)	**Allowable Exceptions for Consultants:**
☐	Where an unforeseen situation of urgency exists and the items, consulting services, non-consulting services or construction cannot be obtained by means of a competitive procurement process. An unforeseen situation of urgency does not occur where OPG has failed to allow sufficient time to conduct a competitive procurement process. Provide further details or justification below:
☐	Where items, consulting or non-consulting services regarding matters of a confidential or privileged nature are to be purchased and the disclosure of those matters through a competitive procurement process could reasonably be expected to compromise government confidentiality, cause economic disruption or otherwise be contrary to the public interest. Provide further details or justification below:
☐	Where a competitive process could interfere with OPG's ability to maintain security or order or to protect human, animal or plant life or health. Provide further details or justification below:
☐	Where there is an absence of any quotations/proposals in response to a competitive procurement process conducted in compliance with OPG-PROC-0058. Provide further details or justification below:
☐	Where the Procurement is in support of Aboriginal peoples. Provide further details or justification below:
☐	Where the Procurement is with a public body. Provide further details or justification below:
☒	Where only one supplier is able to meet the requirements of a procurement in the following circumstances: • To ensure compatibility with existing products. Compatibility with existing products may not be allowable if the reason for compatibility is the result of one or more previous non-competitive Procurements. Provide further details or justification below: The current benchmarking process was developing by ScottMadden in collaboration with OPG in 2009. ScottMadden Consulting is most familiar with the existing process being used by OPG and is in the best postion to expedite the review that is being requested. • To recognize exclusive rights, such as exclusive licenses, copyright and patent rights, or to maintain specialized products that must be maintained by the manufacturer or its representatives. Provide further details or justification below: • For the Procurement of items and services the supply of which is controlled by a supplier that has a statutory monopoly. Provide further details or justification below:

Single Source / Sole Source Justification

(2)	**Allowable Exceptions for Items and Non-Consulting Services:**
☐	Where an unforeseen situation of urgency exists and the items, consulting services, non-consulting services or construction cannot be obtained by means of a competitive procurement process. An unforeseen situation of urgency does not occur where OPG has failed to allow sufficient time to conduct a competitive procurement process. Provide further details or justification below:
☐	Where items, consulting or non-consulting services regarding matters of a confidential or privileged nature are to be purchased and the disclosure of those matters through a competitive procurement process could reasonably be expected to compromise government confidentiality, cause economic disruption or otherwise be contrary to the public interest. Provide further details or justification below:
☐	Where a competitive process could interfere with OPG's ability to maintain security or order or to protect human, animal or plant life or health. Provide further details or justification below:
☐	Where there is an absence of any quotations/proposals in response to a competitive procurement process conducted in compliance with OPG-PROC-0058. Provide further details or justification below:
☐	Where the Procurement is in support of Aboriginal peoples. Provide further details or justification below:
☐	Where the Procurement is with a public body. Provide further details or justification below:
☐	Where an award is made under a co-operation agreement that is financed, in whole or in part, by an international organization only to the extent that the agreement includes different rules for awarding Contracts. Provide further details or justification below:
☐	Where construction materials are to be purchased and it can be demonstrated that transportation costs or technical considerations impose geographic limits on the available supply base, specifically in the case of sand, stone, gravel, asphalt compound and pre-mixed concrete for use in the construction or repair of roads. Provide further details or justification below:
☐	Where there are directed regulatory or shareholder requirements (e.g., directions/requests from the Canadian Nuclear Safety Commission [CNSC]). Provide further details or justification below:
☐	Where OPG is contracting with a subsidiary of OPG or another entity where OPG is able to appoint 50 percent of more of the Board of Directors. Provide further details or justification below:
☐	Where there is concrete and demonstrable evidence that a particular supplier is the only entity that is capable of providing the solution OPG needs. Provide further details or justification below:

Single Source / Sole Source Justification

☐	Where only one supplier is able to meet the requirements of a procurement in the following circumstances: • To ensure compatibility with existing products. Compatibility with existing products may not be allowable if the reason for compatibility is the result of one or more previous non-competitive Procurements. Provide further details or justification below: • To recognize exclusive rights, such as exclusive licenses, copyright and patent rights, or to maintain specialized products that must be maintained by the manufacturer or its representatives. Provide further details or justification below: • For the Procurement of items and services the supply of which is controlled by a supplier that has a statutory monopoly. Provide further details or justification below: • For the purchase of items on a commodity market. Provide further details or justification below: • For work to be performed on or about a leased building or portions thereof that may be performed only by the lessor. Provide further details or justification below: • For work to be performed on property by a contractor according to provisions of a warranty or guarantee held in respect to the property or original work. Provide further details or justification below: • For a Contract to be awarded to the winner of a design contest. Provide further details or justification below: • For the Procurement of a prototype or a first item/service to be developed in the course of research, experiment, study, or original development but not for any subsequent purchases. Provide further details or justification below: • For the purchase of item(s) under exceptionally advantageous circumstances such as bankruptcy or receivership, but not for routine purchases. Provide further details or justification below: • For the Procurement of original works of art. Provide further details or justification below: • For the Procurement of subscriptions to newspapers, magazines or other periodicals. Provide further details or justification below: • For the purchase of real property. Provide further details or justification below:

Single Source / Sole Source Justification

APPROVALS:			
Requested By:			
Signature:			
Name:	**John Blazanin**	Date:	**Mar 11 2015**
Title:	**Director Controllership, Nuclear Finance**		
Organizational Name:	**Nuclear Finance**		
Reviewed By Supply Chain (in accordance with Organizational Authority Register Element 7.2):	☐ Approved	☐ Rejected	
Comments:	approved per Management's instructions		
Signature:			
Name:	R Zamarripa	Date:	3/18/2015
Title:	Sr MGR STR. Sourcing		

ONTARIO POWER GENERATION

PURCHASE ORDER

Mail Invoice To:
ONTARIO POWER GENERATION INC.
P.O. BOX 850
135 WEST BEAVER CREEK
RICHMOND HILL ON L4B 4R7

Purchase Order	: **00263961**
Revision	:
Release	:
Facility	: COR
Printed	: **02AUG2016**
Page	: **1**

Please Direct Inquiries to:
AMIR R. MIRSHAHI
AMIR.MIRSHAHI@OPG.COM
Title: STRATEGIC PLANNING
Phone: 416-231-4111 **Ext:** 4262

Vendor:
MARC MILLER
SCOTTMADDEN INC
2626 GLENWOOD AVE
SUITE 480
RALEIGH NC 27608
UNITED STATES

****** DUPLICATE COPY ******

Payment Terms % Days Net 99 Days
ERS N Reference Contract

Primary Ship To: ONTARIO POWER GENERATION INC
HEAD OFFICE
700 UNIVERSITY AVENUE
TORONTO ON M5G 1X6

Attention: NON

Fac	Standard Name	S/P	Text	Header Terms and Conditions - Text at End
	ARIBA-NO-ERS	S	Y	PO INVOICING TERMS FOR NON ERS SUPPLIERS ON ARIBA
	SUPPLEMNT-1	V	Y	SUPPLEMENTARY TERMS AND CONDITIONS

Line	*Quantity*	*UP*	*Item Description*	*Unit Price*	*Extension*

ONTARIO POWER GENERATION

PURCHASE ORDER

Mail Invoice To:
ONTARIO POWER GENERATION INC.
P.O. BOX 850
135 WEST BEAVER CREEK
RICHMOND HILL ON L4B 4R7

Purchase Order : 00263961
Revision :
Release :
Facility : COR
Printed : 02AUG2016
Page : 2

0001 1 LO **Catalog ID:** **USD**
TAXABLE

Schedule: **Quantity** 1 **Delivery Date** 31AUG2016

Description: CONSULTING SERVICES

Purchase Order Total Amount

AUTHORIZED SIGNATURE
Amir R Mirshahi
Digitally signed by Amir R Mirshahi
DN: cn=Amir R Mirshahi, o=Supply Chain, ou=Strategic Sourcing, email=amir.mirshahi@opg.com, c=CA
Date: 2016.08.02 07:51:38 -04'00'

Line	Fac	Standard Name	Variable Terms and Conditions
		SUPPLEMNT-1	SUPPLEMENTARY TERMS AND CONDITIONS

All in accordance with:
1. The requirements of this Purchase Order;
2. PO Invoicing Terms;
3. The commercial terms of OPG Contract Standard A29-15 Consulting Services;

This Purchase Order is the governing contract document. Subsequent instruction notices shall take precedence for matters in which the purchase order is amended.

Instructions will be contractually binding only when issued in writing by Supply Chain Division. Communications (verbal or otherwise) from other Ontario Power Generation departments will not be recognized as changing the scope, price or terms of the contract.

WORK REQUIRED:
" Understand exactly how OPG is normalizing TGC/MWh
" Conduct research on:
- Comparable utility capital projects
- Related utility finance approaches to measuring value for money, especially TGC/MWh
- Corresponding regulatory opinions
" Compare research findings to OPG approach
" Develop and document ScottMadden opinion on OPG approach in report
" Send draft of report to OPG for review and feedback
" Review OPG feedback, incorporate as appropriate, and finalize report
- Schedule: Complete the work no later than end of August 2016
- Estimated Budget: Based on resourcing the above, I would expect the cost

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Purchase Order :	**00263961**
Revision :	
Release :	
Facility :	COR
Printed :	**02AUG2016**
Page :	**3**

not-to-exceed US$25,000

Completion date:
End of August 2016

KEY PERSONNEL:
(not limited to)
Marc D. Miller, Partner

Fac	**Standard Name**	**Terms and Conditions**
	ARIBA-NO-ERS	PO INVOICING TERMS FOR NON ERS SUPPLIERS ON ARIBA

Ontario Power Generation Purchase Order and Invoicing Terms For Suppliers Using Ariba

Ariba Electronic Commerce

The Supplier acknowledges that OPG has implemented Ariba, an electronic commerce system, and the timely payment of amounts owing to the Supplier requires that the Supplier provide invoicing information in accordance with this system. Upon crossing a transactional threshold, Suppliers may incur a charge to transact with OPG using Ariba. OPG will not pay license or configuration fees for the integration, implementation, and usage of Ariba.

Ariba Supplier Membership Program Details can be found at:

http://www.ariba.com/suppliers/subscriptions-and-pricing/supplier-membership-program/pricing

Purchase Order

If this Purchase Order (which includes any document incorporated by reference in this Purchase Order and excludes any invoice, waybill or other document issued by the supplier/contractor) is not confirmed in Ariba, both parties agree that if the supplier/contractor indicates that it has agreed to provide the good/services described in this Purchase Order in any way, then the terms of this Purchase Order govern exclusively, including if: (i) the Purchase Order is executed by the supplier/contractor; (ii) goods and/or services are delivered in whole or in part by the supplier/contractor to OPG; or (iii) any

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payment is made by OPG to the supplier/contractor. For clarity, any invoice, waybill or document issued by the supplier/contractor will not apply.

This purchase order is not to be amended in any way without the issuance of a purchase order revision from the purchasing unit. Invoice payments will only be processed based on the terms and conditions of issued purchase order, a purchase order revision or, if applicable, the executed agreement.

No substitutions are permitted without the prior written approval and/or purchase order revision from the purchasing unit.

Upon receipt of a Purchase Order, all Suppliers are required to enter a Confirmation in Ariba within 7 days.

This Confirmation will provide an Estimated Delivery Date and provide the Supplier capability to adjust the Price or Quantity.

When Price or Quantity is adjusted, OPG will issue a Purchase Order Revision which will also be sent back to Ariba. The Supplier is expected to provide a Confirmation on this Revision, with the latest Estimated Delivery Date.

OPG will NOT issue a Purchase Order Revision where only an Estimated Delivery Date is being provided by the Supplier. Unless there is a change to price, quantity or other non date related updates, you can proceed with the order based on the most current version in Ariba.

Shipments of Goods

Suppliers are not to ship goods to Ontario Power Generation until they have received the most recent version of the Purchase Order on Ariba. If a Supplier has submitted an Order Confirmation asking for a price or quantity adjustment but still waiting for a new version of the PO to arrive on Ariba, there is no authorization to proceed and goods must not be shipped.

When Supplier is ready to ship product we ask that a Shipment Noticed is entered into Ariba on or 1 day before the goods are shipped. This information will allow the Buyer to track your shipments and help to provide a more expeditious process when shipments need to be located.

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For shipments with test reports, critical documents etc, the capability to attach these documents to the Shipment Notice is available. In the event that documents are lost OPG will have a secondary method to retrieve them and use them to process the incoming shipment without it being sent to a holding/quarantine area.

Payment Terms

Where the purchase order indicates "99" under "Net Days", OPG will aggregate all outstanding invoices received and approved for payment before the 25th of each month. Subject to withholdings required by law, statute or regulation, OPG will pay the supplier this aggregate amount on the 25th day, or following business day if the 25th falls on a non-business day, of the following month.

Invoicing

All invoices will be submitted using Ariba. All other methods of invoice submission will be returned to the Supplier with instructions to enter directly online using Ariba.

Suppliers may add multiple attachments to their electronic invoice for supporting documentation. Attachments can be in any format such as: .PDF, .TIF, .JPG, .BMP, .XLS, .DOC, .PPT. Attachments can be up to 100 MB. The 100 MB limit applies to the total size of all attachments associated with the document.

A new and unique invoice number must be provided for each invoice unless resubmitting a corrected invoice that previously had a failed or rejected status

OPG does not support the Ariba Network feature to cancel invoices. Suppliers must issue a credit invoice to cancel a previously submitted invoice.

Payment will be withheld for any non-conformance issues until such time that the issue is resolved. Material goods received into

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inventory require acceptance approval prior to release of payment. Receipts completed by OPG are visible in your Ariba Account.

Invoice Status Updates

Real-time invoice status updates are available in Ariba. Should you wish to also receive these status updates by email you can configure your Ariba account to do so.

If you have questions on how to submit an invoice using Ariba, or how to configure your account to receive regular status updates on your submitted invoice, please follow the instructions in the hyperlinks below. If you have questions please contact Ariba at 1-866-218-2155.

How to Submit an Invoice to OPG using Ariba for Services (PDF)

How to Submit a Progress Payment Invoice to OPG using Ariba (PDF)

How to Submit an Invoice to OPG for Material Supplied (PDF)

How to View the Status of an Invoice Submitted to OPG (PDF)

How to Configure Email Notices for Invoice Status Changes (PDF)

Questions and Help

OPG encourages our Suppliers to contact Ariba directly with questions on how to use the Ariba application for processing Confirmations, Ship Notices, and Invoices.

Ariba can be reached at 1-866-218-2155.

Additional help documents can be found at:
http://www.opg.com/working-with-opg/suppliers/supply-chain/Pages/Electronic-Commerce-FAQs.aspx#S13FAQ Id3

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PURCHASE ORDER

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Purchase Order	:	**00263961**
Revision	:	
Release	:	
Facility	:	COR
Printed	:	**02AUG2016**
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The Standard Purchasing Clauses that follow this page form part of the Purchase Order and are identified by Title under PO Header Terms and Conditions, and Cat ID Line Terms and Conditions. If you do not have the correct revision number for any of the reference documents identified in the Purchase Order under the PO Header and Cat ID Line Terms and Conditions, please contact the Buyer for the correct revision.

SCHEDULE A - Statement of Work

This Statement of Work is subject to the terms and conditions of the Standard Commercial Terms for Consulting Services executed between Ontario Power Generation Inc. ("OPG") and The Hackett Group Canada Inc. ("Hackett") dated November 5, 2015 ("the Consulting Agreement").

Requirement 1: Benchmarking Report

The Consultant must compile relevant information on corporate support functions and costs and prepare a report that compares OPG's performance with relevant industry peers, which at minimum, includes the following (the "Benchmarking Report"):

1. description of the methodology used to gather, analyze and report the results, including:
    a. High level overview of the methodology used to collect and verify OPG's data in a similar fashion to other utility companies to ensure accurate comparability (in a way that does not disclose the Hackett Process Taxonomy or data of the individual companies)
    b. The rationale behind the use of specific metrics in the analysis – specifically explanations behind why particular metrics were selected
    c. Peer group selection criteria and peer group profiles (in a way that does not identify individual peers)
    d. The corporate support functions included in the analysis (in a way that does not disclose the Hackett Process Taxonomy)

2. functions that are in-scope, which include:

    a. Finance
    b. Human Resources
    c. Real Estate
    d. Information Technology
    e. Executive and Corporate Services

    At a minimum, the following areas are out of scope:

    i. All offices or operations of the unregulated portion of OPG
    ii. For the Supply Chain function, warehouse management and logistics
    iii. For the Finance function, the revenue cycle
    iv. Corporate costs allocated to the Darlington Refurbishment Project

3. presentation of OPG's quartile performance relative to its peers, including:
    a. Total corporate costs and the cost for each in-scope function for OPG
    b. Total corporate costs and the cost for each in-scope function for peers on a quartile basis (in a way that does not identify individual benchmarking data of any peers)
    c. Performance will be presented for 2010 (Starting Period) and for 2014 (Current Period).[1]
    d. For each period, OPG's performance will be compared to a relevant peer group. The consultant will work with OPG to select two groups of peer companies from the Hackett Benchmark Program that best meet the requirements for this project. One peer group will be used for Starting Period comparisons and another peer group will be used for Current Period comparisons.

    The Consultant will work with OPG to select metrics that best meet the requirements for this project.

[1] For the Current Period, 2013 data may be used if 2014 data is not available.

4. presentation of the results in a manner that facilitates transparent and meaningful comparison before and after the introduction of OPG's Business Transformation initiative, which commenced in 2011.

OPG is permitted to disclose and publish in the public domain the Benchmarking Report as described in the Consulting Agreement.

Initial draft of the Benchmarking Report must be submitted to OPG for OPG's review no later than January 29, 2016. The completion date for the final Benchmarking Report is February 29, 2016.

Billing:

The fee structure for all of the services set forth in this Statement of Work to complete the Benchmarking Report is a flat fee basis. The total flat fee, not including project travel and expenses and telecommunications charges, for the Benchmarking Report as defined in this Statement of Work is CAD 92,000.

Travel and expenses for on-site services are not included in the amount above. Travel and expenses will be billed separately as incurred, and are estimated to be CAD 13,500.

Invoicing Information:

Accounts Payable (AP) Contact: ______________________________
AP Contact Email Address: ______________________________
AP Contact Phone Number: ______________________________
Do you have a PO number that will need to be on the invoice? ______________
If yes, please provide the PO number or expected date for PO number receipt: __________
Do you require Hackett to post invoices to your portal? ______________
If yes, please provide the URL/Web site/Portal along with User id & password: __________
Any special billing instructions for Hackett's Accounting Team? ______________

Requirement 2: Potential to Support Evidence in OPG's Next Rate Application(s)

The Consultant must be prepared to participate in OPG's next hydroelectric and nuclear applications including, but not limited to, the following activities: preparing evidence, responding to interrogatories, providing oral testimony, responding to undertakings and supporting the preparation of argument.

Requirement 2 will be carried out on a time and materials basis.

All activities will be performed on an as required basis at OPG's request. For each work package, OPG will provide the Consultant with specific instructions and the Consultant will then provide OPG with a forecast level of effort to complete the work at agreed upon hourly rates. OPG will then approve the Consultant's forecast in advance of the work being undertaken.

OPG expects to file its next rates application with the OEB in Q2 of 2016.

Accepted and Agreed

OPG By:	[signature]	Hackett By:	[signature]
Name:	Colin Anderson	Name:	Anthony Snowball
Title:	Director - Ont. Reg. Affairs	Title:	Practice Leader, Benchmarking
Date:	Nov. 20/15	Date:	November 23, 2015

AMPCO Interrogatory #2

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

Interrogatory

Reference:
Ref: A2-2-1 Page 5

Preamble: The evidence states "OPG continues to employ leading practices in the business planning process, including top-down target setting for key resource envelopes such as OM&A, capital and headcount."

a) Please summarize what OPG believes to be leading practices in the business planning process.

b) Please provide the specific top-down targets set for OM&A, capital and headcount over the test period.

c) Please explain any differences between headcount and FTEs.

Response

a) OPG considers leading practice in business planning to be an effective, integrated process that aligns business plans and budgets with corporate strategy using a flexible model with key stakeholder engagement and the appropriate level of detail. The key attributes of an effective business planning process are timeliness, efficiency, accuracy, transparency, depth, insight and clarity.

b) The 2016-2018 top-down targets for OM&A, capital and headcount are found at Ex. A2-2-1, Attachment 2, pp. 10-13.

   As explained at Ex. A2-2-1, pp. 2-3, planning information for all years of the 2016-2021 period was developed as part of the 2016-2018 planning cycle on the same basis and through a consistent process. Specific resource targets were set for the 2016-2018 period while other tools such as benchmarking, other performance indicators and trend analysis were used to develop business unit inputs into the 2019-2021 financial projection. All years were reviewed internally as part of the OPG Board-approved submission.

c) Headcount is the staffing level at the end of a year. FTEs or full-time equivalents represent the number of hours worked over the year converted to an equivalent number of full-time employees. Please see Ex. L-6.6-1 Staff-136.

AMPCO Interrogatory #3

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

Interrogatory

Reference:
Ref: A2-2-1 Page 1

Preamble: The evidence indicates that OPG's Business Plan supports Ontario's Climate Change initiatives.

a) Please provide the costs budgeted in this application (labour and non-labour) to address Ontario's Climate Change initiatives including Cap and Trade.

Response

OPG supports Ontario's climate change objectives in that the company's regulated generating facilities produce virtually emission-free electricity. OPG does not specifically plan its business or track costs in relation to the referenced climate change initiatives.

The Province's Cap and Trade initiative would result in an immaterial increase to the price of fossil fuels such as diesel fuel that OPG uses in the emergency standby generators at the nuclear facilities. No other spending or budget in the regulated nuclear operations is tied to the Province's climate change initiatives.

AMPCO Interrogatory #4

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

Interrogatory

Reference:
Ref: A2-2-1 Page 4

Preamble: The evidence indicates OPG has been challenged to find further cost reductions and efficiency gains.

a) Please confirm the key initiatives regarding productivity and efficiency improvements are found at pages 31, 35 and 37 of A2-2-1 Attachment 1.

Response

a) Confirmed.

AMPCO Interrogatory #5

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

Interrogatory

Reference:
Ref: A2-2-1 Attachment 1 Page 31

Preamble: At Page 31, OPG provides a list of six initiatives that are aimed at closing performance gaps in order to achieve targeted results for the Nuclear business unit.

a) Please provide further details on the design and status of Workforce Planning and Resourcing initiative and any documents provided to senior management and OPG's Board of Directors to approve this initiative.

b) Have any savings been identified over the test period as a result of implementing the six initiatives listed on Page 31? How have they reflected in the current application?

Response

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

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

   The initiative was approved as part of the business plan (Ex. A2-2-1 Attachment 1, p. 31). The Terms of Reference (see Attachment 1) were approved by the Nuclear Executive Committee which receives regular updates on the initiative.

   The cross-functional representatives of the Resource Planning and Control Team are working with Nuclear operations to prepare long term fleet staffing plans. The process to maintain oversight of identified hiring needs has been established to ensure there is an integrated view to Nuclear resourcing.

b) The nuclear initiatives listed on page 31 of the referenced exhibit are to bridge the gaps between current performance and the targeted results as presented in the rate filing. Thus, while savings have not been quantified, the benefits are reflected in the current application. For example, the equipment reliability initiative will contribute to Darlington being able to meet its 1% Forced Loss Rate ("FLR") target and to Pickering being able to sustain its 5% FLR target. The exception is the Workforce Planning & Resourcing Initiative which will have longer term benefits outside of the rate application period at PECO.

Resource Planning & Control Team
Terms of Reference

Business Need: In recognition of the need to recruit significant numbers of staff into the organization, and concurrently manage the impact of Pickering End of Commercial Operations (PECO), integrated long term fleet staffing plans are required to ensure sufficient resources are available for safe and reliable operation, and carrying costs are minimized post PECO.

Goal: Establish robust, long-term (10 year) staffing plans for each functional area that optimizes the allocation of resources across the nuclear fleet. These staffing plans define the movement of staff between sites within functional areas, and provide the input for yearly external recruitment of staff. Staffing plans will be refreshed yearly and cover a rolling 10 year window.

Mandate: The Resource Planning and Control Team is a formal team established jointly by the President OPG Nuclear and the VP, HR Business Partners Nuclear. The mandate of this team is to critically examine and challenge staffing plans, and provide concurrence, to ensure:

- Station requirements, including Refurbishment, have been incorporated and addressed or dispositioned
- Workforce staffing models have been effectively used to predict changes in staffing levels and also to evaluate potential staffing scenarios
- Requirements of applicable Collective, and Mid-Term, agreements, have been satisfied
- Proposals fit within Business Plan funding envelope or the requirement for additional funding has been clearly defined and documented
- Competing scenarios have been evaluated, and sound, defendable decision criteria have been used to select the recommended staffing strategy
- Staffing strategies have considered use of all staffing options including regular, temporary, and augmented staff, use of the internal transfer process, and also contracting out specific blocks of work
- Training requirements have been clearly defined and training can be delivered within the specified timeframe to ensure capability is maintained
- The recommended staffing strategy is the best option for OPG, adequately balancing short and long term needs and considerations, as well as being tightly aligned to OPG priorities and overall direction
- Leaders within the functional area have agreed and signed off on the strategy signifying their commitment to execute as written

Process:

- The oversight/control team will be comprised of representatives from HR, Finance, Fleet Ops & Mtce, Engineering, Senior Site & Refurb Representatives, Labour Relations, and Workforce Planning.
- There is a materiality limit for submission of staffing plans and strategy to the team in that requests for reallocation of approved HC within an organization, outage staffing requirements, or hiring fewer than 5 people into an organization does not require concurrence by this team. It is important to point out that subdividing requests to subvert this materiality limit will not be tolerated.
- Each year, each functional area shall present an updated 10 year staffing strategy to the RCPT for review, challenge and concurrence. It is expected this will be a product of the peer teams within the functional area. The following functional areas are covered in this requirement:
  - Operations
  - Maintenance
  - IMS
  - Engineering
  - Radiation Protection
  - Emergency Services
  - Projects
  - Work Management
- The team will conduct a thorough examination of the plan to ensure it satisfies the business need.
- The team will ensure that all additional approval requirements such as additional funding or special labour agreements have been documented, and there is a plan of action with timelines for securing these additional approvals.
- The team will endorse staffing plans for each functional area by issuing a memo to the CNO, or designated approval authority, seeking approval to implement the plan. This memo will clearly document required internal transfers, and any external hiring required.
- The team will ensure support is provided to the recruitment and hiring processes for Engineering, Operations and Maintenance.

Guiding Principles:

- Staffing strategies will:
  - Optimize internal transfers and the use of non-regular employees in accordance with the PWU and Society collective agreements, and PECO Mid-term.
  - Ensure health of succession pipeline.
  - Optimize the mix of regular and non-regular staff.
  - The Nuclear process will be integrated with the corporate staffing process.

- Hiring criteria will include leadership potential and diversity goals.

Meeting Schedule: The Team will meet monthly at a minimum. More frequent meetings may be needed to address issues that require urgent and/or timely action.

Quorum: Team members are:

VP Fleet Ops and Maintenance (Chairperson)
SVP Engineering
SVP Projects and Refurbishment
Director HR -Nuclear Support
Labour Relations SPOC
Finance SPOC
Workforce Planning SPOC
Senior Line Station SPOC (DN and PN)
PECO SPOC
Staffing SPOC
Training SPOC

AMPCO Interrogatory #6

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

Interrogatory

Reference:
Ref: A2-2-1 Attachment 1 Page 35

Preamble: At Page 35 OPG lists the following initiative for its Hydro-Thermal business: Productivity Improvements: This initiative focuses on continued review of opportunities for efficiency gains from strategic initiatives, optimizing the productivity of maintenance staff, and focusing on the Attendance Support Program."

a) Does OPG have any similar or other productivity initiatives for its nuclear business?

Response

Yes, OPG continues to drive to nuclear efficiency improvements as per the initiatives in the business plan, similar to productivity initiatives for its hydro thermal business. Actions to improve productivity are embedded in the following initiatives listed in Ex. A2-2-1 Attachment 1, p. 31 and in Ex. F2-1-1, pp. 19-22:

- Human Performance Initiative
- Equipment Reliability Initiative
- Outage Performance Initiative
- Parts Improvement Initiative
- Inventory Reduction Initiative
- Workforce Planning and Resourcing Initiative

As discussed in Ex. F2-1-1, pp. 11-13, the initial Goodnight study in 2011 indicated that OPG Nuclear was 17 per cent above its industry peers (normalized for CANDU technology differences) and that OPG has since eliminated the gap in 2016.

AMPCO Interrogatory #7

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

Interrogatory

Reference:
Ref: A1-4-1 Page 2

a) Please provide a listing of all of the reports from the Audit and Risk Committee prepared that are relevant to the current application.

b) Please provide a status report on the recommendations from the Audit and Risk that are relevant to the current application.

c) Please provide the 2017 to 2021 workplan for the Audit and Risk Committee.

Response

(a) The Audit and Risk Committee does not issue reports.

(b) The Audit and Risk Committee makes recommendations to the OPG Board of Directors around the company's financial reports, internal audit function, external auditor, business and financial planning including rate applications, investment funds and risk management. To the extent that these matters affect this application, they are fully discussed in OPG's evidence. In any event, neither the list requested in part (a) nor the status report requested in part (b) of this interrogatory seek to elicit relevant information about the matters at issue in OPG's application.

(c) No work plan covering any of the years from 2017-2021 currently exists.

AMPCO Interrogatory #8

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

Interrogatory

Reference:
Ref: A1-4-1 Page 3

a) Please provide a listing of all of the reports from the Compensation, Leadership and Governance Committee that are relevant to the current application.

b) Please provide a status report on the recommendations from the Compensation, Leadership and Governance Committee that are relevant to the current application.

c) Please provide the 2017 to 2021 workplan for the Compensation, Leadership and Governance Committee.

Response

(a) The Compensation, Leadership and Governance Committee does not issue reports.

(b) The Compensation, Leadership and Governance Committee makes recommendations to the OPG Board of Directors around the company's compensation philosophy and principles, and objectives for total compensation; CEO compensation; Director compensation; pension plan changes; and executive benefit plans. To the extent that these matters affect this application, they are fully discussed in OPG's evidence. In any event, neither the list requested in part (a) nor the status report requested in part (b) of this interrogatory seek to elicit relevant information about the matters at issue in OPG's application.

(c) No work plan covering any of the years from 2017 to 2021 currently exists.

AMPCO Interrogatory #9

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

Interrogatory

Reference:
Ref: A1-4-1 Page 3

a) Please provide a listing of all of the reports from the Darlington Refurbishment Committee that are relevant to the current application.

b) Please provide a status report on the recommendations from the Darlington Refurbishment Committee.

c) Please provide the 2017 to 2021 workplan for the Darlington Refurbishment Committee.

Response

a) Please see L-4.3-6 EP-19 (c).

b) Please see L-4.3-6 EP-19 (c).

c) No work plan covering any of the years from 2017 to 2021 currently exists.

AMPCO Interrogatory #10

Issue Number: 1.2

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

Interrogatory

Reference:
Ref: Exhibit A2-1-1 Attachment 1 Page 10

Preamble: The evidence states "In the first quarter of 2014, the OSC approved an exemption which allows OPG to apply US GAAP up to January 1, 2019."

a) Please discuss OPG's strategy in 2019 and beyond regarding US GAAP versus IFRS and the impact on revenue requirement of any anticipated adjustments.

Response

a) Refer to Ex L-01.2-1 Staff-2a).

CME Interrogatory #12

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

Interrogatory

Reference:
Ref: Exhibit A2, Tab 2, Schedule 1, page 1 of 10

CME wishes to better understand OPG's business planning and budgeting process that unpins this application. To this end:

(a) Please provide all presentations, PowerPoint slides, briefing notes or other written memoranda prepared by the business units developing their business plans and presented to OPG's senior management;

(b) Please provide all written questions, comments or directions provided by OPG's senior management to OPG's business units relating to any presentations, PowerPoint slides, briefing notes, other written memoranda or draft business plans;

(c) Please provide all presentations, PowerPoint slides, briefing notes, or other written memoranda prepared by OPG for OPG's Board of Directors relating to the business planning and budgeting process, including draft corporate level consolidated information, summarized financial plans, operational targets, and key initiatives for OPG's major business units;

(d) Please provide all written questions, comments or directions provided by OPG's Board of Directors to OPG relating to the information set out in (c) above.

Response

OPG declines to provide the requested documents on the basis of relevance as explained in response to L-11.1-3 CME-4(c). OPG has provided the business plan that was approved by its Board of Directors and underpins this application in Ex. A2-2-1, Attachment 1.

CCC Interrogatory #2

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/p. 7

Please provide all materials that were presented to the OPG Board of Directors when seeking approval of the 2016-2018 Business Plan in May 2016.

Response

Ex. A2-2-1 Attachment 1 is all the material that was presented to OPG's Board of Directors in May 2016 when seeking approval of the 2016-2018 Business Plan.

CCC Interrogatory #3

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 1

The Business Plan states:
"To increase the return on the Shareholder's investment to more commercial levels, the Company will focus on maximizing production, continuing to pursue cost efficiencies, and increasing net income by exploring new business growth strategies in both the core business and emerging generation technologies." Please elaborate on what these new business growth strategies are and how they will be funded.

Response

The business growth strategies referenced relate to OPG's unregulated business and therefore are not relevant to the setting of payment amounts for the prescribed assets.

CCC Interrogatory #4

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 1

The Business Plan identifies 5 key risks:

1. Failure to maintain cost and schedule commitments for the DRP;

2. OEB decisions that do not provide adequate cash flow and recovery of costs;

3. Inability to retain and attract leadership talent and qualified management employees during the DRP and the continued Pickering operations;

4. Adverse impact of life management and equipment aging issues on nuclear generation; and

5. Impact of financial market conditions on pension, OPEB and nuclear waste obligations and related funds.

For each of the key risks please set out, in detail, how OPG is planning to mitigate those risks through the test period.

Response

1. OPG has planned extensively to enable successful execution of the DRP. As described in Ex. D2-2-4, the company has prepared a detailed scope and a high-confidence schedule and cost estimate, with a focus on minimizing the risk of scope creep, schedule delays and associated cost increases. The extensive evidence filed in Exhibit D2, Tab 2 speaks to the efforts taken to ensure that the DRP is delivered safely, on-time, and on-budget.

2. OPG will review the OEB's decision in this application and determine what actions, if any, are required to ensure adequacy of cash flows to meet operating needs and for future investment in capital, including the DRP.

3. OPG will continue to review its staffing and compensation strategies and plans in order to attract and retain skilled employees necessary to ensure continued safe and efficient

operations and successful completion of key initiatives, such as the DRP (for example, see Ex. F4-3-1, Ex. L-4.3-2 AMPCO-087 and Ex. L-11.4-1 Staff-255 (a)).

4. The evaluation of equipment aging issues and their impact on nuclear production is a core priority of the nuclear business, impacting all aspects of operations from maintenance strategies to engineering evaluations to project investments or modifications. Please see the overview of the nuclear business in Ex. F2-1-1 for further details. As noted on page 14 of Ex. F2-1-1, OPG has set operational and financial targets for the nuclear business, "cognizant of the current reality that Darlington and Pickering are aging facilities, which will require significant investment and operational excellence to achieve the desired outcome of low cost, safe and reliable generation."

5. The business plan assumes costs for pensions, OPEB and nuclear liabilities based on existing information about financial market conditions such as discount rates, investment returns and inflation. Subsequent changes to these assumptions can significantly impact costs, particularly as these are long-term obligations, presented in present value terms. Changes in these inputs are generally based on market conditions and are not controllable by OPG. OPG monitors these factors

   The funded status and funding requirements of the pension plan are determined periodically through actuarial valuations (see Ex. F4-3-2 and Ex. L-6.6-1 Staff-156). The funded status and funding requirements of the nuclear segregated funds are determined in accordance with the Ontario Nuclear Funds Agreement (Ex. C2-1-1).

CCC Interrogatory #5

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 2

The Business Planning Instructions were issued in May 2015. How often are these instructions issued? Please file the instructions that were issued for the previous business planning cycle. Have new instructions been filed since 2015 for future planning? If so, please file that document.

Response

The business planning instructions are issued annually for each business planning cycle.

The instructions issued in 2015 and filed as Ex. A2-1-1 Attachment 2 were for the 2016-2018 business planning cycle, the results of which underpin this payment amounts application. The instructions issued in 2016 for the 2017-2019 business planning cycle are found at Ex. L-1.2-1 Staff-3, Attachment 1.

OPG declines to provide the instructions issued in 2014 for the 2015-2017 business planning cycle on the basis of relevance. These instructions do not underpin OPG's request for payment amounts in this application and are not relevant to deciding any issue on the approved Issues List.

CCC Interrogatory #6

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 2

The Business Planning Instructions indicate that a key strategic goal for OPG is to improve its financial performance and specifically its net income and return on equity. Would OPG accept an earnings sharing mechanism (ESM) whereby earnings in excess of the allowed return would be used to reduce its payment amounts? If not, why not. If so, under what conditions would an ESM be acceptable to OPG?

Response

The ESM mechanism proposed in the question appears apply to overearnings only. OPG believes that a one-sided ESM would generally be inconsistent with the ratemaking principles of fairness and balancing the effects on both customers and shareholders.

In addition, any ESM should be calculated based on OPG's total regulated earnings, including both regulated hydroelectric and nuclear generation lines of business. OPG operates as a single company, with a single management structure and a single cost of capital that covers both the hydroelectric and nuclear generating facilities. On this basis, OPG believes that it would be appropriate for any earnings sharing to be done on the same total company basis. To do otherwise would be inconsistent with the basis on which existing rates were set.

CCC Interrogatory #7

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 2, p. 6

In the Business Planning Instructions document it states that one of the assumptions is "end of life" for all units at Pickering will be 2020. How did the 2016-2018 Business Plan change when the decision was made to extend the Pickering Operations until 2024?

Response

The 2016-2018 business planning process in relation to Pickering Extended Operations is described at Ex. A2-2-1, p. 5, line 26 to p. 6, line 12. In summary, the 2016-2018 business planning process required planning information to be prepared both on the basis of the original base case assumption of Pickering operations to 2020 as well as Pickering Extended Operations to 2022/2024. The latter set of information was reflected in the 2016-2018 Business Plan approved by the Board of Directors in May 2016.

Relative to the original base case of Pickering operating to 2020, the approved 2016-2018 Business Plan included:

- incremental OM&A costs for enabling Pickering Extended Operations, as shown at Ex. F2-2-3 Chart 2,
- OM&A and project portfolio capital costs to restore ongoing operating and maintenance programs to normal levels as discussed in Ex. F2-2-3 section 3.3.2, and
- corresponding changes to the generation plan throughout the planning period, as discussed throughout Ex. E2-1-1.

CCC Interrogatory #8

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

Interrogatory

Reference:
Reference: Ex. A2/T2/S1/Attachment 4, p. 3
With respect to OPG's asset management and project review process there is reference to the post implementation review process (PIR) which is an appraisal process designed to evaluate whether planned results of a given investment have been met following completion. It further states that the two main objectives of the PIR process are to verify whether the benefits stated in the project business case were realized, and to capture the lessons learned from each project so they can be applied to improve future projects and other investment decisions.

a. Please provide an example of a PIR that followed a simplified format and one that followed a comprehensive format;

b. Was a PIR undertaken for the Niagara Tunnel Project? If not why not? If so, please provide it;

c. How many projects are subject to a PIR appraisal each year?

Response

Attachment 1 provides an example of a Post Implementation Review (PIR) that followed a simplified format. Attachment 2 (which contains confidential content as marked) provides an example of a PIR that followed a comprehensive format.

a. Yes. The PIR for the Niagara Tunnel Project is currently undergoing final review and approval. OPG will update this response to provide a copy when it is approved.

b. On average over 2014 to 2015, OPG's nuclear business conducted about 20 PIRs per year.

Simplified Post Implementation review

Station:	Project Name:	Project No.:	Units:	Controlled Doc No.:
Pickering B	Standby Generator Governor Upgrades	13-49109	056, 078	NK30-PIR-54600-00004

Approval	Cost	Date
Original Approval Estimate	$21,680K	Mar 2006
Approval Revision Estimate		
Final Approval Estimate	$22,872K	Mar 2007
Final Actual Project Cost	$22,751K	Jan 2015

Timing	
Target Date	Dec 2007
Latest Approved i/s Date For all 6 SG's	Jun 2008
In Service Date with modification of all 6SG's	Aug 2008
Period used to calculate Performance result	Jan-2009 to Jun-2015

BRIEF DESCRIPTION OF PROJECT

This project is one of the initiatives for SG upgrades designed to reduce the likelihood of a forced outage due to obsolescence and parts unavailability that has been negatively impacting reliability. Prior to the start of the initiative, Pickering B SG performance was showing deteriorating trend. Design basis start reliability targets were not met. Approximately 70% of the total SG trips were identified due to deficiency of SG start up controls & permissive issues. Continued degradation would have potentially caused severe, protracted adverse impact on SG performance that would led to forced unit outages due to unavailability of Standby Class III power redundancy. Objective of the project is to improve start reliability as per Design Basis, reduce failures and increase availability & reliability of Standby generators.

BCS Recommendations:

A total of $22,872,000 was recommended for release to complete final installation of the Standby generator governor Upgrade project by June 2008.

This project is designed to reduce the likelihood of a forced outage due to obsolescence of SG controls and spare parts unavailability that has been negatively impacting reliability. Scope of the project is based on Pratt & Whitney report IMR#510 issued in the year 1999 which focused on equipment obsolescence issues and OEM's inability to support critical products.

This project is one component of the REGM 28007285 committed to CNSC.

Scope for Project# 13-49109

-Governor fuel delivery system replacement
-New PLC based integrated governor and sequencer controls
-Replace majority of the relay based start/control logic with PLC
-Independent over speed protection system
-PLC based speed switches and timers
-New data event logger with expansion facilities
-New Machine Monitor – Temperature & Vibration

Financial:

Project# 49109 came $121,000 under budget.

DELIVERABLES	
Target	**Achievement**
Measurable Parameter: Available For Service (first 2 SG's) Targeted Results: AFS and Open Items acceptance by stakeholders How it will be measured: Attach copy of AFS and Open Items	Available for service dates for first 2 SG's are as below:- 1.056-54600-SG3: AFS date 13-Oct-2006 Attachments: i) Copy of AFS report as per N-FORM-10091 ii) OPEN items as per AR# 28070181; Current status: Complete 2.078-54600-SG3: AFS Date 22-Dec-2006 Attachments: i) Copy of AFS report as per N-FORM-10091 ii) OPEN items as per AR# 28073103; Current status: Complete **Note**: - All 6 SG's have been completed with modification; last SG was completed on 15-Aug-2008. Supporting data has been provided for first 2 SG's only as per deliverables per BCS. Available for service dates for remaining SG's:- 3.056-54600-SG1: AFS date 20-Jul-2007 4.078-54600-SG1: AFS Date 22-Oct-2007 5.056-54600-SG2: AFS date 28-Dec-2007 6.078-54600-SG2: AFS Date 15-Aug-2008
Measurable Parameter: SG Machine performance criteria met Targeted Results: Commissioning results acceptance by Design How it will be measured: Signed commissioning report scanned in Passport	SG Machine performance criteria were met and commissioning results accepted by Project Design for all 6 SG's. Signed commissioning reports are in ASSET SUITE. Details of commissioning reports for first 2 SG's are as below:- 1. NK30-CR-54600-00034: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG3 – Cover page attached. 2. NK30-CR-54600-00038: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG3 – Cover page attached. Commissioning reports for remaining SG's are as below:- 3. NK30-CR-54600-00042: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG1. 4. NK30-CR-54600-00043: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG1. 5. NK30-CR-54600-00047: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG2. 6. NK30-CR-54600-00051: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG2.

Measurable Parameter: Standby Generator System Health Targeted Results: Removal of SG Governor and associated control system as contributor to RED system Status How it will be measured: Updated SG system Health report indicating improved status for affected equipment	Overall U058 SG System Health is consistently 'WHITE" since Jan-2009 till to date. Copy of Cover page of Health Report is attached for the year 2009 (Jan- Jun) and for the year 2015 (Jan-Jun).
Measurable Parameter: REGM #28007285 complete Targeted SG Governor Project contribution to REGM completion How it will be measured: SMB REGM schedule review milestone added to SG outage plan	SG Governor Project contribution to REGM AR# 28007285 completed on 15-Aug-2008. Memo NK30-CORR-00531-04903 sent to CNSC on 29-Aug-2008 providing status update on completion of Standby Generator Upgrade Project – Copy attached.

QUALITATIVE RESULTS	
Health & safety	No health & safety incidents were reported during the project.
Lower maintenance costs	Governor and logic failures minimized due to installation of upgraded PLC based system and new components.
Diagnostic capabilities	Improved diagnostic capabilities using new data logger and machine monitor, thus reducing trouble shooting time. Also, it eliminated the need for Maintenance/Eng to be present for every test run.
Reduction in CM/DM backlogs	Replacement of obsolete system with PLC based system resulted in reduction in CM/DM backlog for governor control components.
KEY LESSONS	
Spare parts for upgraded Governor controls	1. Lifetime spare parts are not adequate considering rate of failure in the last 6 years of operation Current Status: Review of lifetime spares completed in consultation with Plant Design - Complete 2. Vendor Taken off ASL while the parts were in transit, resulted in quartine of parts. Current Status: Team has been engaged for pursuing balance parts as detailed under "Follow up actions".

Variable Frequency Drive	Variable frequency drive terminal block rating was incorrect for the application. Current status: Replacement terminal blocks installed on all 6 SG's.
Annunciator Panel	Frequent annunciator lock up occurred on all SGs resulted in OPS memo. Current Status: New annunciator Panel installed on all 6 SGs
Vibration cards	Initially installed vibration cards were not suitable for high temperature application for Turbine end. Current Status: Vibration cards replaced for high temp application.
HP Fuel pump recirculation Solenoid valve	Sticking of solenoid valve: SG Start up failures due to sticking of solenoid valve (Failed closed) in the Fuel pump bypass line. Current Status: Design review completed and Software Modification installed.
FOLLOW-UP ACTIONS	
Spare parts for upgraded Governor controls	Spare parts team comprising of members from Perf Eng, Plant Design, Procurement Eng and Supply Chain is working on getting lifetime spares on shelf. Current status: Out of total of 188 spares, 173 spares are on hand, PO has been placed for 5 items and remaining 10 items are in progress. Status of spares is tracked at PHC dashboard bi-weekly

Prepared by: NKumar Date: 18-NOV-2015

Naresh Kumar
SE, Standby Generators

Reviewed by: M. Knutson for Date: Nov 27, 2015

Dean Townsend
Director- Station Eng

Approved by: Carlo Crozzoli Date: 21 Dec 15

~~Beth Summers~~ Carlo Crozzoli
Interim SVP and Chief Financial officer

Approved by: [signature] Date: 5 Jan 15

Jeff Lyash
President & CEO

Attachments:-

1. Copy of BCS for Pickering B Standby Generator Upgrade project 13-49109
2. Project Closure Report
3. Copy of Letter to CNSC, ref# NK30-CORR-00531-04903 dated August 29, 2008
4. Completion of REGM AR#28007285
5. Available for service, Open item list and Commissioning reports for 056-SG3 & 078-SG3
6. Cover page of System Health Report

ONTARIO POWER GENERATION

Report

Internal Use Only Commercially Sensitive	
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Title:
FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW

Fuel Handling Power Track Capital Improvement Project (16-31438) - Comprehensive Post Implementation Review

D-PIR-63578-10001-R001
2013-04-29

Order Number: N/A
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Reviewed by: 30 April 2013
Steve Ramjist Date
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Reviewed by: May 1/2013
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Approved by: 13-06-18
Tom Mitchell Date
President and CEO

Table of Contents

List of Tables and Figures

Revision Summary

Revision Number	Date	Comments
R000	2013-03-27	Initial issue.
R001	2013-04-29	Added management note to executive summary.

Preface

Contributions and Acknowledgments

The CPIR team interviewed the following people and their contribution to the review is much appreciated.

Terry Acheson
Mario Campigotto
Brian Duncan
Paul Mather
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The CPIR Team

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Executive Summary

A unique design feature of CANDU reactors is that they allow for online fuelling operations. This is accomplished through the reliable operation of the fuel handling systems. Darlington has 3 pairs of fuelling machine heads capable of fuelling all 4 units. The fuelling machine heads are delivered to the units using any one of three trolley pairs. In 2004 a power track roller failed, detached from the system, and became entrained in the power track chain. The entangled roller halted motion of the power track and caused extensive damage to the supporting steel work. The resulting recovery, repair work, and production losses cost the company $45 M (SCR D-2004-00642).

As a result of the root cause analysis of the 2004 event, the Fuelling Machine Power Track Rehabilitation Project 16-38451 was initiated which included a comprehensive list of OM&A and capital funded initiatives. The first initiatives to be undertaken included a risk assessment, cable chain replacement and flat bar re-welding. In March of 2006, modifications and maintenance improvement related scope items, including the detection and surveillance systems, were removed from this project and split into two new projects (16-31438 and 16-38472).

The proposed scope of the Fuel Handling Power Track (FHPT) Capital Improvement Project (16-31438) included a dynamic instrumentation system (DI), a dropped roller detection system (DRD) and an enhanced video surveillance system (VSS). In the end only VSS was completed for a total cost of $16.12 M.

The project approval authority called for a Comprehensive Post-Implementation Review (CPIR) of project 16-31438 due to dropped scope, $3.35 M in capital cost write-offs to OM&A, cost increases and schedule delays. An independent CPIR team was formed in January of 2013 to conduct a review of the project as per the CPIR Terms of Reference (see Appendix A).

The FHPT Capital Improvement project was successful in terms of cost and schedule when compared only to the Phase 2 Full Release Business Case Summary (BCS) approved in 2010. A surveillance system has been put in place, which allows remote inspection and real-time monitoring of the FHPT. However, not all VSS cameras are fully functional and outstanding actions still exist.

When looking back at the project, the CPIR team concluded that overall cost performance was not acceptable and scope management and implementation during the project was not well executed. The Partial Release BCS approved in late 2007 forecasted the final project cost to be $9.3 M and included three modifications (DI, DRD and VSS). The Phase 1 Full Release BCS approved in early 2009 forecasted the final cost of the project to be $17.38 M for the three modifications. In mid 2009, five years after the initial event, OPG requested a project scope assessment from the Original Equipment Manufacturer (OEM). The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

For project 16-31438, the problem definition and business need statement of improving FHPT reliability was very general leading to several initiatives. The business need did not focus on the root causes determined during the 2004 event investigation. Also, no initial value engineering or third party assessment was done on the identified alternatives.

The relationship between initiatives under the various FHPT projects was not fully understood or managed. The increased FHPT reliability due to roller endplate replacements reduced the overall risk and this was first mentioned in the partial release BCS for project 16-31438 in 2007. This was an early indication that some planned initiatives might no longer be needed but no reassessment was done.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of the project. This was a result of the OEM assessment leading to a joint review by Fuel Handling and Design Projects. The joint review determined that there was low value for money in proceeding with DI and DRD.

Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.

The Phase 2 Full Release BCS in 2010 forecasted the final cost of the project to be $16.16 M, which is approximately $1 M less than the previous BCS, but the scope of the project had been reduced to the VSS modification.

A major challenge for this project was the unpredictable installation schedule. Installation required the use of No Fuel Windows (NFWs). The project installation work did not have priority status for NFWs and committed NFWs had a tendency to move. The missed NFWs added substantial cost to the project when contractors were placed on standby. Through teamwork and communication between the projects organization and the station later in the project, Fuel Handling mini outages were used to complete the installation.

The CPIR team conducted a thorough assessment of project management practices, BCS quality and project outcomes. Project documentation was reviewed and project stakeholder interviews were conducted. Lessons learned have been summarized in Section 6 of this report. Recommendations based on the key themes of the lessons learned have been documented in Section 7 and are summarized below.

Recommendation 1: Fuel Handling Mini Outages bring Predictability to Project Installation Schedules

The CPIR team recommends that the use of FH mini outages with committed dates be explored as an alternative to the use of NFWs for project installation work. NFWs have a tendency to move and competing station priorities may result in bumped project work. Resources can then be assigned to project installation work with more certainty, increasing the probability of achieving project schedule and cost estimates.

Recommendation 2: Milestones and Other Time Pressures should not take priority over Project Management Best Practices

The CPIR team recommends that project management best practices should not be sacrificed to meet deadlines. Milestones should not be declared complete when actions to meet the milestone are still outstanding.

Recommendation 3: Major projects resulting from High Profile Events should undergo an Initial Independent Assessment of the Business Need and Identified Alternatives

The CPIR team recommends that a third party assessment be done early in projects resulting from high profile events. After a major station event, emotions are running high and there is an urgency to quickly correct the identified causes. An independent assessment of the proposed solutions would help identify if those solutions are feasible, if they meet the business need and whether the alternative analysis has been thorough including comprehensive stakeholder involvement.

Recommendation 4: Clear and Specific Problem Definition and Business Need Statement need to be developed at the beginning of a project

The CPIR team recommends that extra scrutiny be placed on the problem definition and business need statement at the outset of the project lifecycle. A clear and specific problem definition linked to root causes is crucial to enable a thorough alternative analysis, scope identification and scope prioritization. All activities throughout the project lifecycle should be continuously checked against the business need to ensure continuity with the problem definition and proposed solution.

Recommendation 5: An approved Project Execution Plan is needed early in the Project Lifecycle

The CPIR team recommends that a thorough project execution plan be prepared and approved during the early stages of a project. A plan should be in place to document, monitor and control all project management knowledge areas to ensure effective project execution.

Recommendation 6: Alternatives to Sole Source Contracts should always be explored

The CPIR team recommends that the justification for sole source work be closely scrutinized to ensure that benefits from the competitive bidding process are not lost. GE was chosen as the sole source for the camera system on the basis of their experience with fuel handling technology. There was no technical basis for this decision, as the surveillance system technology is not dependant on any unique aspects of the fuel handling system technology.

Recommendation 7: An improved Document Repository and Versioning System is required

Having a proper document control system for working documents is useful for tracking changes and ensuring documentation is not lost. Documentation was lost at various stages of the project. Lost documentation leads to rework and loss of information crucial to decision making. Asset Suite and shared drives are not an effective means of managing working documents.

Management Note:

Darlington Station management and Projects and Modifications management have reviewed the recommendations in this report and concur with the recommendations. It was noted that some actions have already been implemented to address aspects of these recommendations. Where actions have not yet been implemented, the Action Tracking process will be used to open new actions, assign owners and track these actions to completion.

1.0 INTRODUCTION

Darlington nuclear generation station is a 4 unit CANDU plant that first went into service in 1990. It provides a total output of approximately 3,500 MWe which is enough to serve the power needs of two million people. A unique design feature of CANDU reactors is that they require online fuelling operations. Reliable operation of the reactors requires reliable fuel handling systems.

Darlington has 3 pairs of fuelling machine heads capable of fuelling all 4 units. The fuelling machine heads are delivered to the units using any one of three trolley pairs. In 2004 a power track roller failed, detached from the system, and became entrained in the power track chain. The entangled roller halted motion of the power track and caused extensive damage to the supporting steel work. The resulting recovery, repair work, and production losses cost the company $45 M (SCR D-2004-00642).

The Fuel Handling Power Track (FHPT) Capital Improvement Project (16-31438) was a result of the root cause analysis following up from the 2004 event. The proposed scope included a dynamic instrumentation system (DI), a dropped roller detection system (DRD) and an enhanced video surveillance system (VSS). In the end only VSS was completed for a total cost of $16.12 M.

The project approval authority called for a Comprehensive Post-Implementation Review (CPIR) of the project due to the material scope change during the execution phase, $3.35 M cost write-off, cost increases and schedule delays.

An independent CPIR team was formed in January of 2013 to conduct a review of the project. As stated in the CPIR Terms of Reference (see Appendix A), the purpose of a CPIR is as follows:

- Verify the achievement of planned benefits identified in the business case and capture any other quantitative and qualitative outcomes of the investment.
- Assess the effectiveness of the project's intent, project charter, project execution plan, project execution, and operational performance results in meeting the business needs and the investment objectives stated in the BCS of the project.
- Review the appropriateness of risk management from business case approval through project completion and document lessons learned in different aspects of risk management including identification, analysis, mitigation plan, and monitoring and control throughout the life of the project.
- Review the effectiveness or quality of the BCS of the project looking back from results to provide feedback for future decisions. The financial evaluation used in the BCS should be re-assessed using actual results and documented in completed PIRs.

The intent of the CPIR is to complete a “cradle to grave” assessment of the project in order to identify lessons learned and recommendations. The report is not written to lay blame but rather to learn from past experience and allow OPG to improve its business management processes going forward. It is much easier to identify early warning signs after a project has been completed.

The CPIR team reviewed project documentation including documentation of other related fuel handling projects. Stakeholder interviews were conducted to fill in information gaps and to gain an understanding of how the project progressed. The team analyzed all the gathered information in order to produce the final report.

The CPIR report provides information consistent with the deliverables outlined in the terms of reference. Section 2 describes the project background and the overall project lifecycle. Sections 3 through 5 provide an assessment of business case summaries, project management related areas and project outcomes. Sections 6 and 7 summarize the lessons learned, conclusions and recommendations.

2.0 PROJECT BACKGROUND

2.1 Project History and Rationale

On January 21st, 2004 at about 16:00 hours, the Darlington FHPT system experienced a functional failure (SCR D-2004-00642 [R-13]). Intermediate roller #11 suffered a mechanical failure and had fallen into the lower cable pan becoming foreign material. The PT guide roller drum ran over the failed intermediate roller and broke free of its mounting. The guide roller drum shaft projected to the south of the main roller drum and began to interfere with supporting steelwork, halting motion of the FHPT system.

The failure caused significant damage to the Trolley (1,2 Power Track system, resulting in a 21 day outage of Unit 2 and a de-rating of Unit 1 to 59% for 15 days. The cost of the failure was estimated at $45 M in lost revenues.

The root cause investigation on SCR D-2004-00642 was completed on March 16th, 2004. The SCR states that roller #11, a blind roller that could only be inspected at one to two years intervals, was missed when reinforced type rollers were installed in all blind roller positions around the end of 2001. The SCR also states that there is strong evidence that the last scheduled inspection identified serious damage on roller #11.

The Incident Investigation Report for SCR D-2004-00642 states that the root causes of the event were:

1. Management failed to recognize the magnitude of the risk associated with operating degraded equipment (Power Track), to properly assess the risk and to follow up on indications of major risks (from SCRs, Health Reports etc.) (Management Direction - Personnel exhibited insufficient awareness of the impact of actions on nuclear safety or reliability)

2. Station Management failed to apply adequate priority to corrective actions initiated to resolve persistent problems with the Power Track (Corrective Action - Response to a known or repetitive problem was untimely)

   Contributing Cause #1: Inadequate commitment to the Corrective Action program on the part of FH Management (Management Direction - Inadequate commitment to program)

   Contributing Cause #2: The design of the reinforced rollers for the Power Track does not meet Station requirements.

SCR D-2004-00642 had a total of 9 assignments (2 to 10). Assignments 2 and 3 were for the design and procurement of replacement rollers to address the immediate issue of failed rollers. Assignment 4 was to determine the feasibility of minor modifications to prevent rollers from failing on the power track. Assignments 5 to 7 addressed changes to corrective action planning in light of the event. Assignment 8 was an extension of a TOE action in order to complete Assignment 9.

Assignment 9 and 10 dealt with the long-term corrective action plan. Assignment 9 was to conduct failure analysis and risk assessment. Assignment 10 was to identify initiatives that would reduce the high risk of failure of the FHPT system.

Following the 2004 FHPT T(1,2 incident, temporary PT inspection cameras were installed as temporary modifications (TMOD) in the PT stationary support frame and on trolleys T(3,4 and T(5,6 to cover off the inspection of blind rollers. The temporary installed trolley cameras were obsolete and no spares were available. These TMODs remained in place until they were replaced with permanent equipment.

2.2 Project Initiation and Planning

2.2.1 Project 16-38451 Fuelling Machine Power Track Rehabilitation

2.2.1.1 Project Charter

In September of 2004 the project charter for the FHPT rehabilitation project 16-38451 [R-01] was issued. This project originally covered all FHPT project work resulting from the January 2004 event investigation. The project need was to improve FHPT reliability and performance and included three major scope areas:

1. System Analysis Work

2. Fuelling Machine Power Track Modifications.

3. Fuelling Machine Power Track Maintenance

Item 1 included a FHPT risk assessment and a study of FHPT dynamics. Item 2 included a number of modifications including the design and installation of a FHPT failure detection system and system surveillance enhancement. Items 1 and 2 were to be managed by Darlington Design projects while item 3 was to be managed by the Fuel Handling organization.

2.2.1.2 2004 Risk Assessment

The DNGS FHPT Risk Assessment P0440/RP/005 [R-14] was issued in November of 2004. The risk assessment analyzed initiating events (usually a component failure) and subsequent events and actions leading to PT failures that could impact trolley motion and fuel cooling. Importance measure quantification analysis was carried out on the subsequent actions to determine the risk reduction worth and risk achievement worth. This determines how sensitive the overall risk value is to the probability of an action or event. It was determined that the most important future event to consider was the failure to detect a guide roller sub-component failure. The dominant contributor (25%) was an event similar to the one described in SCR D-2004-00642 but with irradiated fuel on board. The assessment concluded that the public risk was negligible.

The Risk Assessment concluded that the financial risk associated with all potential power track failures was estimated to be $17 M per year and was substantial. The report warranted exploring the benefits/costs of potential improvements to reduce the risk and preventative maintenance efforts focussed on minimizing roller failures.

A list of initiatives was developed to address the risk of FHPT failure. The Risk Assessment results were used as the rationale behind the need to reduce risk.

2.2.1.3 Project 16-38451 Scope and Releases

The original estimates for project 16-38451 indicated that all packages would be available for service (AFS) by the end of 2007 for a cost of $12 M, including $0.95 M for the detection and surveillance system. General Electric (GE) was indicated as the design agency and would complete the design packages for all aspects of the project.

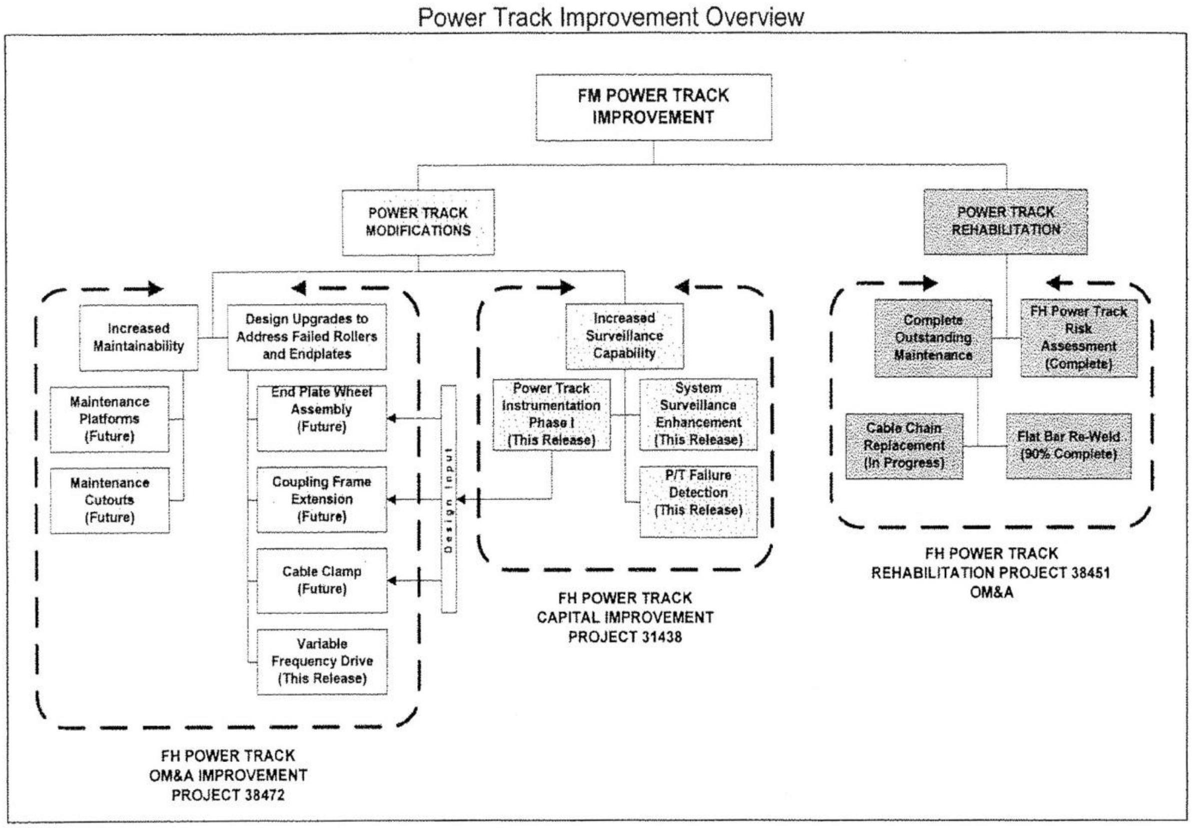
In March of 2006 a full release business case summary for project 16-38451 [R-02] was approved for a total of $7.90 M for this project. Modifications and maintenance improvement related scope items, including the detection and surveillance systems, were removed from this project and split into two new projects (16-31438 and 16-38472). At this point in time, no money had been spent on the detection and surveillance system items.

Project 16-38451 was closed out on May 2nd, 2008 for a total cost of $6.74 M as per the project closure report [R-03].

2.2.1.4 Status of FHPT Rehabilitation and Improvement Projects at Year End 2007

The following schematic provides an overview of the re-aligned FHPT-related project scopes at the end of 2007:

Figure 2.1: Overview of Fuelling Machine Power Track Improvement initiatives in late 2007



2.2.2 Project 16-31438: Fuel Handling Power Track Improvement (Capital)

In April of 2006 the project charter for the FHPT Improvement Capital Funded Project 16-31438 [R-04] was issued. The project need was to improve the reliability and performance of the Darlington FHPT by implementing the required modifications. The objectives were:

1. Design and installation of a Dynamic Instrumentation System (DI)

   DI would be a permanent instrumentation system to monitor dynamics, vibrations and forces acting upon the FHPT system and to provide early detection of component failure.

2. Design and installation of a Surveillance System (VSS)

   VSS would replace a number of temporary cameras and provide remote coverage of 100% of the critical FHPT components to aid in failure detection.

3. Design and installation of a Failure Detection System (DRD)

Dropped Roller Detection (DRD) would provide immediate and responsive indication of significant intermediate roller failures.

The AFS for all work packages was estimated to be December of 2008 for an estimated total of $2.88 M.

2.3 Project Execution

On May 28th, 2007 the initial developmental business base summary (BCS) [R-05] for preliminary engineering of DRD and DI and to pursue alternatives for VSS was approved for $1.38 M. This BCS covered two FH projects (16-31438 and 16-38472) which were the result of the scope splitting from the original FHPT rehabilitation project (16-38451). The total estimated cost for both projects was $16.98 M of which $10.94 M was estimated for the capital project. Installation was being targeted for the 2009 vacuum building outage (VBO). It was proposed that General Electric (GE) would be the sole-source design agency for all aspects of the project except for the VSS portion. Other options for VSS enhancement were being pursued at this time due to high estimates received from GE.

On November 13th, 2007 a partial BCS [R-06] was approved for $4.40 M to commence design activities. This BCS also covered both the OM&A and capital projects. The total estimated cost for both projects was $14.28 M with $9.29 M for the capital portion. Preliminary engineering was in progress for all modifications except for VSS which was under negotiations for the design portion of the work. VBO installation was still being targeted at this time. FH Technical had now assumed the roles of Modification Team Leader (MTL) and Field Team Leader (FTL) for the VSS portion of the project.

On January 26th, 2009 a full release BCS [R-07] for phase 1 was approved for a further $8.53 M to complete detailed design, installation and closeout of the remaining VSS releases (release 2, 3 & 4) and DI. This BCS was to also fund a DRD trial to determine feasibility and to determine if a phase 2 release will be required for DRD installation and closeout. This BCS covered only the capital project and the new estimated total was $17.38 M. Some VSS work was injected into the VBO window and the rest was to be done using the online process.

In August of 2009 the Original Equipment Manufacturer (OEM), KabelSchlepp, issued an assessment [R-10] of the FHPT. The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M [R-09] was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of the OEM assessment [R-10] leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

On July 29th, 2010 the phase 2 full release BCS [R-08] was approved for an additional $1.83 M for the completion of the VSS for a final total of $16.16 M. This BCS covers the remaining design, procurement, installation, commissioning and closeout of VSS. Previous releases covered the design of the first 3 VSS releases and the materials and installations of releases 1 and 2. The increased cost is attributed to schedule delays and higher than estimated costs associated with design, procurement and pre-installation activities. The BCS states that a Comprehensive Post Implementation Review was now required.

2.4 Project Closure

The FHPT capital improvement project was declared available for service through operations acceptance on November 30th, 2011. There were 59 outstanding action tracking items related to the project at the time of AFS (see Appendix B). Refer to section 5.0 for details regarding cameras that have failed and still require repair.

The project closure report [R-11] was issued on November 2nd, 2012. The final actual cost was $16.12 M which was lower than the phase 2 full release estimate of $16.16 M which included [redacted] of contingency. The project closure date was October 31st, 2012 which is one month earlier than forecasted.

A project Lessons Learned document [R-12] was issued on January 16th, 2013 shortly after the CPIR process began. The CPIR report will be prepared by the end of March 2013, thus closing the loop on the entire project. These were deliverables mentioned in the phase 1 full release and to be completed under the phase 2 work but the project was closed before their completion.

The related project for FHPT OM&A improvements, Project 16-38472, was closed out on October 11th, 2012 for a total cost of $2.13 M. The completed scope of work included installing strain relief on the moving and fixed ends of the 3 trolley pairs and installing soft starting devices on the 3 trolley motors.

2.5 Project Life Cycle

The time line for project 16-31438 is summarized in Figure 2.2, below, in the context of the overall FHPT improvement initiatives. The project charter was issued in April 2006, with final reduced scope of VSS enhancements going into service by November 2011.

Figure 2.2: Basic Timeline for Darlington FHPT Projects and Related Events

Jan-04	FHPT Event

	Rehab OM&A Improv. Project 38451
Sep-04	38451 Project Charter • project scope: (a) system analysis work, (b) 9 FH PT modifications (mods) & (c) FH PT mtce
Nov-04	NSS Risk Assessment completed
Mar-06	38451 BCS - Project Full release

	Capital Improv. Project 31438		OM&A Improv. Project 38472
Apr-06	31438 Project Charter	Apr-06	38472 Project Charter
May-07	31438 BCS - Developmental release	May-07	38472 BCS - Developmental release
Nov-07	31438 BCS - Partial release	Nov-07	38472 BCS - Partial release
Jan-09	31438 BCS - Full release Phase 1		
Aug-09	OEM Assessment of FHPT cable condition		
Nov-09	31438 OM&A Cost Write-off		
		May-10	38472 BCS - Full release
Jul-10	31438 BCS - Full release Phase 2		
Nov-11	31438 Report of Equip. In-service		
		Oct-12	38472 Project Closure
Nov-12	31438 Project Closure		

3.0 BUSINESS CASE SUMMARY ASSESSMENT

3.1 Project Releases

A business case summary (BCS) provides a concise outline of the information required by the approval authority to release a specific level of funding needed to achieve specific results in terms of scope, schedule and costs, with an understanding of the associated risks. BCSs are often prepared as a project proceeds through the project gates between project phases such as the initiation phase, definition phase and execution phase.

A summary of the project releases for project 16-31438 is provided in Table 3.1:

Table 3.1: Summary of Capital Improvement Releases

Date	Capital Project Release			Total Capital Project	
	Type	Amount	Scope	Estimated Cost	Full Scope
May-07	Developmental	$1.4M	• preliminary engineering for DRD & DI • pursue alternatives for VSS design	$10.943M listing estimate (+100% to -50%)]: - [redacted]	VSS, DRD, DI
Nov-07	Partial	$4.4M	• scope: complete design of DI, DRD & VSS PMODS • prepare for installn (2009 VBO)	$9.3M [conceptual estimate (+60% to -25%)]: - [redacted]	VSS, DRD, DI
Jan-09	Full release Phase 1	$8.5M	• install VSS release (rel) 2 during VBO; design/install VSS rel 3 & 4; commission VSS [AFS Sept 2010] • procure/ install/ commission DI [AFS July 2011] • install DRD pilot with full implemtn in next release • train Ops&Mtce & Perf Eng staff • revise Ops Mtce procedures	$17.4M [release quality estimate +15%/-10%]: - [redacted]	VSS, DI, pilot DRD
Jul-10	Full release Phase 2	$1.8M	• VSS going ahead; DRD and DI cancelled - previous release: Design of VSS rel 1, 2 &3; matl purchase & install of VSS rel 1&2 - this release: design VSS rel 4; matl purchase & install of VSS rel 3 &4; commission VSS • project closeout	$16.2M [release quality estimate +15%/-10%]: - [redacted]	VSS
Nov-12	Project Closure			• final cost : $16.1M	VSS

3.2 Alternative Analysis

The Alternatives presented in the Nov. 2007 partial release BCS included the following capital improvement scope:

- Base Case: Do nothing beyond the short term reliability measures pursued under project 16-38451
- Alternative 1: Install the VSS enhancements, DI & DRD (recommended)
- Alternative 2: Delay the VSS enhancements, DRD & DI for 2 years
- Alternative 3: Install the DRD only
- Alternative 4: Install the VSS enhancements only
- Alternative 5: Install the DI only

The reason given for not pursuing Alternative 4 was that it "would not address reliability and may not detect a dropped roller in time to prevent damage".

In the January 2009 phase 1 full release BCS, Alternative 1 had changed to recommending a phased implementation of the DRD system instead of its full implementation. The same reasons as in the 2007 partial release BCS were given for not recommending Alternative 4. The Base Case stated that although there had been significant improvements to the PT including weld repairs, endplate roller replacements & increased maintenance which may improve overall reliability, the underlying causes of PT failure still continued to exist and needed to be better understood for long term reliability.

During 2009, an assessment of the FH PT cable condition was conducted by the OEM. It became evident that more critical system health issues (cable degradation, chain wear) affecting reliable operation of the PT needed to be implemented over the proposed monitoring systems (DI, DRD).

In the July 2010 phase 2 full release BCS, the recommended alternative changed to completing installation of the VSS enhancements and dropping the DI & DRD scope altogether. Reasons for installing the VSS enhancements included that the current temporary VSS was unreliable and had component obsolescence issues and, as such, might reduce station availability of each FM pair and might leave PT failures undetected.

3.2.1 Lessons Learned

LL 3.2.1: At the start of a project, the problem definition and Business Need statement should be defined in the most specific terms possible, allowing specific solutions to be identified and prioritized based on the expected benefit attributable to each solution.

LL 3.2.2: A thorough review of the alternatives should be conducted in the early project phases (initiation phase, early definition phase) to review their implementation practicality and requirements, including the cost and schedule requirements. The evaluation of the alternatives should involve all stakeholders (design, operations, maintenance, OEM, etc.) and should consider the project-specific constraints such as the limited availability of No Fuel Windows in this case.

3.3 Estimate Accuracy

The project estimates developed during the various project releases are summarized in Table 3.1. The estimates including contingencies for the full project scope of VSS, DI & DRD were as follows:

- $10.9 M in May 2007 (developmental release) including [redacted]% contingency
- $9.3 M in November 2007 (partial release) including [redacted]% contingency
- $17.4 M in January 2009 (full release phase 1) including [redacted]% contingency

The phase 1 full release BCS had a release quality estimate (+15%/-10%) prepared after extensive front end planning including input from a third party estimator. The increased cost was partly due to the planned installation of most of the VSS equipment using the online process and not during the 2009 VBO.

In November 2009, a $3,347 K write-off was made for the DI and DRD scopes of work. The write-off resulted from an assessment of the PT cable condition by the OEM in mid 2009, followed by a joint review by Design Projects and Fuel Handling, which determined these initiatives to be low value for money because more critical system health issues (cable degradation and chain wear) needed to be addressed.

The DI and DRD initiatives were not proven technology and did not have a history of use in similar systems and, as such, carried more risk in terms of their design, implementation and value.

In the end, the project cost was $16.1 M for the installed VSS alone. Assuming the VSS scope was 1/3 of the estimated total project cost of $17.4 M in the phase 1 full release BCS, this represents an increase from $6 M to $16 M of the VSS system costs from January 2009 to July 2010. Cost increases were due to schedule delays and higher that estimated design, procurement and installation support costs. It was during this time that the DI and DRD were dropped from scope.

3.4 NPV Evaluation

For the developmental, partial and phase 1 full release business cases, the Base Case assumption was that the cost to OPG of doing nothing was $17 M/yr. This cost comes from the 2004 FHPT risk assessment report which assessed a financial risk of $17 M/yr to OPG for all the potential events leading to power track failures that could impact trolley motion and/or fuel cooling. The 2004 risk assessment was based on an event tree methodology used in OPG reactor risk assessments. When the FH PT Improvement program was initiated after the 2004 incident, the $17 M/yr financial risk to OPG was the financial risk being addressed by undertaking all the scopes of work included in projects 16-38451, 16-31438 and 16-38472. In other words, it was determined that these were the scopes of work which would prevent “all potential events leading to power track failures that could impact trolley motion and/or fuel cooling”.

However, as time progressed, and project 16-38451 scope was completed, the financial risk of doing nothing, or $17 M/yr, was not reduced by the contribution of the completed project 16-38451 scope of work towards reducing this risk. The developmental and partial releases for projects 16-38472 and 16-31438 and even the phase 1 full release for 16-31438 continued to use the full $17 M/yr financial risk in the base case in calculating the present value to OPG of the Base Case. This likely overstated the potential benefit to OPG of pursing the scopes of work proposed in these releases.

It should be noted that this was a sustaining project and as such, a positive net present value to OPG is not a requirement for the recommended alternative to proceed. The net present value of an alternative is calculated by subtracting the present value (PV) of the Base Case from the PV of the alternative. It is important that the inputs and assumptions used in the PV calculations of the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.

The challenge in re-evaluating the NPV calculation for project 16-38472 is in determining a realistic valuation of the financial risk to OPG of not pursuing this specific scope of work. For the 2010 phase 2 full release BCS, it was determined that the annual financial risk to OPG of not proceeding with the VSS enhancements was the following:

- major failure of guide roller or subcomponent with irradiated fuel on board and cooling maintained resulting in a 2 unit 60 day outage to recover [3.6% probability]
- failure of guide roller or subcomponent with no irradiated fuel on board resulting in a 1.5 unit 30 day outage to recover [7.5% probability]
- major failure of guide roller or subcomponent with irradiated fuel on board and cooling failure [0.2% probability]

Given that the final cost of the project was close to the cost estimate included in the phase 2 full release BCS, the re-evaluation of the NPV calculations in that BCS would yield the same results.

3.4.1 Lessons Learned

LL 3.4.1: When several major scopes of work are associated with reducing a financial risk to the company, the outstanding (remaining) financial risk used in the financial evaluation in successive business cases should be revised to reflect the outstanding (non-retired) portion of the financial risk, as appropriate.

LL 3.4.2: It is important that the inputs and assumptions used in the financial evaluations, or NPV calculations, for the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.

3.5 Deliverables

The 2010 phase 2 full release BCS for project 16-31438 stated the project would provide the following deliverables:

- In service declaration of VSS releases 2 & 3 by Aug 2011
- In service declaration of VSS releases 4 by Nov 2011
- VSS providing 100% visual coverage of the PT area
- Upgraded VSS will improve roller visibility and overall PT coverage to facilitate Operations and Engineering with current observation and inspection practices
- Qualitative factors:
    - Improved operator and engineering visibility of PT components without entering containment (lower radiation doses)
    - Improved reliability of VSS reducing trolley out of service caused by camera failures
- CPIR completed by November 2012 including evaluation of the stated measurable parameters listed in Table 3.5
- Key lessons learned documented in a project Close-out Lessons Learned Report.
- Project closeout

The deliverables in the 2009 phase 1 full release BCS for project 16-31438 also included training for Operations, Maintenance and Performance Engineering staff on the new systems as well as new and/or revised Operating and Maintenance procedures.

4.0 PROJECT MANAGEMENT ASSESSMENT

4.1 Project Charter

4.1.1 Overview

The project charter for project 16-31438 [R-04] was issued in April of 2006. The stated business need was to improve the reliability and performance of the Darlington FHPT. The objective was to permit safe and long term reliable operation by implementing DI, DRD and VSS. The proposed project close out milestone was December 2008 and the estimated cost was set at $2.88 M. GE was mentioned as the agency to be used to provide technical and design support.

4.1.2 Lessons Learned

LL 4.1.1: Project charters should not identify the specific solutions including specifying the design agency to be used for the proposed modifications. Other options should be pursued rather than jumping to a sole-sourcing design solution that could be more costly than other options.

LL 4.1.2: The problem definition and business need statement should be as clear and specific as possible from the beginning of the project. In this case it is very general and it is difficult to relate the proposed solutions to the business need. A general problem statement leads to scope development and prioritization issues later in the project lifecycle.

4.2 Project Execution Plan

4.2.1 Overview

As per N-PROC-AS-0039 (superseded) every project must have an approved Project Execution Plan (PEP) to monitor and control the project. The PEP should be prepared during the definition phase and before the execution phase of the project.

The only approved PEP for project 16-31438 [R-15] was prepared in December of 2009 and approved in February of 2010. This PEP addressed VSS release 3 and 4. An earlier PEP was prepared in 2008 to address DI, DRD and VSS but was lost and never approved. The preparer had prepared the PEP prior to leaving on rotation. The staff preparing the PEP in 2009 were not aware of the original PEP.

The BCSs made reference to proposed PEP approval dates but these documents were never produced and approved. A PEP was approved after DI and DRD were dropped from scope and was developed in parallel with the final BCS (see Table 4.1).

Table 4.1: Proposed vs Actual PEP Approval Dates

BCS	Proposed PEP Approval Date	Actual PEP Approval Date
Developmental	Dec 2007	No PEP
Partial	Aug 2008	No PEP
Full Phase 1	Feb 2009	No PEP
Full Phase 2	No Proposed Date	Feb 2010

4.2.2 PEP Quality

The following documents were prepared and approved under the PEP:

1. Basis of Estimates
2. Summary of Cash Flow
3. Risk Management Plan
4. Resource Management Plan
5. Schedule P5
6. Quality Management Plan

The Contract Management Plan was developed as a separate document.

The following missing documents from this PEP should have been included to make it effective:

1. Scope Management Plan
2. Schedule Management Plan
3. Cost Management Plan
4. Communication Management Plan

4.2.3 Lessons Learned

LL 4.2.1: Project Execution Plans (PEP) should be developed in parallel with the BCS. The PEP helps document, monitor and control various key project management areas. The BCS should be a summary of much of the information outlined in the PEP.

LL 4.2.2: Project Execution Plans should contain plans for all project management areas. Project 16-31438 had many scope, cost and schedule management issues. The existence of a proper PEP could have helped mitigate the risks.

LL 4.2.3: Proper turnover and document management processes need to be followed for OPG projects to ensure no loss of information. A PEP was developed in 2008 but was lost and never approved. Information from this PEP could not be used for the development of the actual approved PEP.

4.3 Scope Management

4.3.1 Scope Identification

Assignment 10 from SCR D-2004-00642 was to identify initiatives to reduce FHPT risks. Stakeholders involved with the project described it as an emotionally driven project and described the process as a “shotgun” approach where a large number of initiatives were quickly identified to attempt to improve FHPT reliability.

The problem definition and need statement of improving FHPT reliability was very general leading to a wide range of initiatives. No initial value engineering or third party assessment was done to ensure the identified initiatives met the business need. The business need also didn’t address the root causes determined during the 2004 event investigation.

The scope of FHPT Capital Improvement project (16-31438) was originally covered under the FHPT Rehabilitation project (16-38451), which started in 2004. At that time all 12 FHPT initiatives identified as a result of the 2004 PT event were considered under the same project. Due to the number of project initiatives, a large number of work packages were not being progressed in a timely manner.

By April of 2006 no progress had been made with a number of work packages including DI, DRD and VSS. They were removed from the scope of project 16-38451 in order to start two new projects, 16-31438 and 16-38472. DI, DRD and VSS make up the scope of project 16-31438 (see Figure 2.1).

4.3.2 Scope Reduction

In December of 2009, DI and DRD were cancelled due to a number of contributing factors:

- New information from a third party (OEM) assessment [R-10] recommended taking a different approach to preventing/mitigating failures in the FHPT. These were covered under project 16-38472.
- In service experience with the new Generation III roller endplates had proved they have a longer life than the previous versions.
- Uncertainties in the availability of installation and commissioning windows and the associated costs of the DRD and DI systems.

There was a $3.35 M write off due to the dropped scope of this project.

The DI portion of the project was intended to provide information necessary to carry out a number of initiatives under project 16-38472 which was being executed in parallel. With the cancellation of DI, a number of these initiatives were also de-scoped.

4.3.3 Scope Management Quality

Under the Scope Management Plan, scope should have been identified, agreed upon and managed as per Project Management Procedures. There was no formal Scope Management Plan prepared for this project.

The initial scope didn't undergo a third party assessment to ensure the initiatives were feasible and actually met the business need. Scope prioritization was not effective as numerous initiatives under the original project (16-38451) were not progressed for the first two years.

The relationship between initiatives under the various FHPT projects was not fully understood or managed. The increased FHPT reliability due to roller endplate replacements reduced the overall risk and this was first mentioned in the partial release BCS for project 16-31438 [R-06] in 2007. This was an early indication that some planned initiatives might no longer be needed but no reassessment was done.

4.3.4 Lessons Learned

LL 4.3.1: Projects with multiple initiatives need to have their scope prioritized to ensure effort is being focused on key areas and areas that need to be completed before others can begin. A Scope Management Plan could have helped document the relationship between initiatives and help prioritize the larger number of initiatives.

LL 4.3.2: Projects consisting of a large number of initiatives should be grouped into a number of separate projects based on the business need and objective they are trying to achieve. This would allow the proper amount of resources to be assigned to each project to ensure progress is being made on all initiatives.

LL 4.3.3: When multiple projects exist for a system, the impact of one project must be assessed on the other projects. Due to several parallel FHPT projects, one project's impact on other projects was not realized. After the roller endplate modification, the performance of the modification should have been assessed before starting the proposed modifications (DRD and DI system) on the same system.

LL 4.3.4: Projects should not contain initiatives requiring design input from the completion of another project. This was the case for project 16-38472, OM&A FHPT Improvement, as shown in figure 2.1. Those initiatives could also be a second phase of the preceding project, only to be executed based on the results of the design inputs. This would reduce effort and money spent on initiatives that were ultimately cancelled due to the cancellation of DI.

LL 4.3.5: Projects resulting from a major station event should initially be reviewed by a third party to ensure the initiatives are feasible and aligned with the stated business need. The OEM should be contacted immediately for input. Emotions tend to be running high after a significant event and an independent look at the proposed solutions should be completed. Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.

4.4 Schedule Management

4.4.1 Overview

In the early stages of project 16-31438 it was mentioned that the project modifications would target a 2009 VBO installation window. In the developmental BCS [R-05], VBO installation was the target and it was identified as a risk due to the time to complete the design and procure the materials. Successful implementation during the VBO would require vendor schedule concessions, prompt BCS approvals and relief from outage milestones. Proposals from GE were already acquired in order to expedite design completion. GE was eventually awarded a sole source contract in order to expedite the design because of their expertise with FH systems.

The VSS portion of the project was done in a phased approach with 4 releases. This allowed work to be grouped for a more structured installation and to capitalize on lessons learned from previous releases. VSS release 2 was eventually executed during the VBO in order to take advantage of the multi-unit outage to run cables. Other VSS releases were completed online using No Fuel Windows (NFW).

After the removal of DRD and DI from the project scope, only the VSS portion was executed. A formal schedule (P5) was prepared and accepted by key stakeholders for release 3 and 4, however a formal Schedule Management Plan was not prepared for this project. This schedule (P5) was prepared based on milestones committed to in the latest BCS.

4.4.2 Scheduling Challenges

The major schedule delays can be attributed to NFW unpredictability and changes to the Reactivity Management Plan. Equipment reliability issues would cause changes to the Reactivity Management Plan in order to ensure zone levels were maintained which, in turn, would result in NFW changes. The impracticality of using NFWs should have been identified earlier in order to determine a better path forward.

Another challenge was obtaining NFWs committed to VSS installation. This resulted from competing work priorities and insufficient communication between the projects organization and FH operations and maintenance. Multiple jobs could have been carried out during the same window but the various work groups believed they were in direct competition for the available time.

Some delays were also attributed to the time required to issue permits and obtain work authorization. Resources weren't adequate to handle the normal work load and the project work load simultaneously.

4.4.3 Scheduling Successes

In the later stages of the project, FH mini outages were used to get the project back on schedule. This was the first time use of such an outage and it proved to be an effective method of improving schedule performance. These outages were committed windows that were longer than regular NFWs which helped by reducing the overhead needed at the beginning of the window. This was made possible through increased communication and teamwork between various groups such as Projects and FH.

The final AFS milestone was achieved despite many scheduling challenges. This can be attributed to the mini outages and the schedule float that was added to mitigate the risk of installation window unpredictability.

4.4.4 Lessons Learned

LL 4.4.1: Time pressure should be avoided in order to follow project management best practices. Targeting VBO installation expedited the design phase of the project which resulted in the use of sole sourcing. This had an impact on overall project cost.

LL 4.4.2: Projects requiring field installation should attempt to have their schedule pre-negotiated and committed to by operations and maintenance. However, the use of NFWs for project installations is ineffective as these windows have a tendency to move and cannot be pre-negotiated.

LL 4.4.3: Fuel Handling projects requiring NFWs for installation, should explore the use of FH mini outages to complete the work. More work can be executed because of the reduction in overhead involved with starting work each time. The mini outages should be planned and committed to like a unit outage.

LL 4.4.4: Projects executed in areas with high radiation and limited accessibility should have adequate schedule float in order to meet installation milestones. Due to unexpected breakdown maintenance issues, most of the NFWs were taken away from this project.

LL 4.4.5: When executing project installation work, extra resources should be assigned for timely application of permits and work authorization.

4.5 Cost Management

4.5.1 Overview

The actual final project costs are outlined in table 4.2 and are in line with the approved phase 2 full release BCS including [redacted]. Costs were managed through assigning appropriate levels of contingency based on the quality of cost estimates (see Section 3.3). Some cost control measures included the use of competitive bidding for VSS release 4 and for the construction portion of the project. Contingency use and approvals were documented using the Project Change Request Authorization Forms (PCRAFs).

Table 4.2: Cost Summary

Cost Stream	Actual $k	Approved $k	Variance $k	Variance %
Project Management & Support	[redacted]			
Engineering				
Procurement				
Construction				
Interest				
Contingency				
Total	16,120	16,156	(36)	0.2

4.5.2 Cost Variance

The cost variance is summarized in table 4.2. Although there were some major variances, the overall actual costs were on target through the use of the approved contingency.

Project management costs were higher than expected due to the administration surrounding installation delays, coordinating schedules and resources, and providing technical troubleshooting. Engineering costs were lower because competitive bidding was done for the design of VSS release 4. Construction costs were nearly double the original estimate. This can be attributed to the unpredictability of the installation schedule. The reactivity management plan changed frequently due to equipment reliability issues resulting in the unpredictability of NFW availability. Costs also increased due to the required 24 hours/day support needed for the fuel handling mini outage that was eventually used for installation.

4.5.3 Cost Change Management

Cash flow changes were approved through the use of Project Change Request Authorization Forms (PCRAF). They outline the justification for the use of contingency throughout the project. Table 4.3 outlines all the PCRAFs associated with project 16-31483.

Table 4.3: Change Approval (PCRAFs)

PCRAF	Approval Date	Description of Change
001	Jun 19, 2008	Change of Labour Contract Award for DI Requesting contingency funding to cover installation Camera release 1, additional design costs for (DI,DRD, Cameras), project management, camera release 1

		installation, DRD installation and DI materials.
002	Sep 22, 2009	VSS Release 3 & 4 design schedule delayed Project contingency request, additional costs for design agency and installation for the VSS system.
003	Jan 05, 2010	Reduce 2009 control budget due to recommending cancellation of DRD and DI from scope.
004	Jan 15, 2011	Change in current approved cash flows; re-allocate budget from 2010 to 2011.
005	Apr 13, 2011	Additional funds for cost of fuel handling mini-outage installation. Restore previously returned funding from previous year.
006	Oct 13, 2011	Additional funding required for delays incurred through 2011 due to fuelling priorities.
007	Oct 31, 2011	Additional funding requested from contingency to cover incurred delays costs for 2011 installation due to fuelling priorities and other work programs.
008	Feb 03, 2012	Additional contingency funds required to cover closeout. Extra costs in 2011 resulted in lower available funds for 2012.

4.5.4 Cost Performance

Cost performance was tracked throughout the project and reported through monthly project updates. Cost performance is compared to the currently approved releases and PCRAFs which makes it difficult to use as a true indicator of overall project cost performance. This project went through a significant scope reduction and resulted in a cost write-off of $3.35 M and the project closure report still indicates a cost performance index (CPI) of 1.00.

The projected project cost nearly doubled in the phase 1 full release BCS in early 2009 (see Table 4.4). The decision to cut DI and DRD from the project scope took place later in 2009, after the design for both had been completed. Even with the massive scope reduction, the phase 2 full release BCS only projected the final cost to be $1.10 M less.

Table 4.4: BCS Release and Estimate Summary

BCS	Release Capital ($k)	Estimated Final Costs ($k)	Scope
Developmental	1,383	10,943	DI, DRD, VSS
Partial	4,417	9,285	DI, DRD, VSS
Full Phase 1	8,530	17,258	DI, DRD, VSS
Full Phase 2	1,826	16,156	VSS

4.5.5 Cost Write-Off

In August of 2009, 5 years after the initial event, the original equipment manufacturer (OEM) issued an assessment [R-10] of the FHPT. The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M [R-09] was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of the OEM assessment [R-10] leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

4.5.6 Lessons Learned

Many lessons learned affecting cost management can be found under other assessment areas.

LL 4.5.1: The CPIR team recommends that project cost performance for project closure reports should also show the deviation from the summary of estimate before contingency. CPI based on the most recently approved release is used for project cost management but the CPIR team feels that this does not give an accurate representation of overall cost performance looking back at a project.

4.6 Risk Management

4.6.1 Overview

The Risk Management Plan (RMP) was prepared under the PEP based on following procedures and governance:

1. Corporate Risk Management Policy – OPG-POL-0004
2. Corporate Risk Management Program and Guidelines – FIN-PROG-FM-001
3. Project Risk Management – N-INS-00120-10014

The RMP is prepared during the definition phase of BCS and should be part of the PEP. With the help of stakeholders, through brain storming, meetings and operating experience, all risks are identified and recorded in the Risk Register. Based on risks identified, contingencies in cost and float in schedule are included.

In the Risk Register, impacts and probabilities of risks were calculated. Response plans were prepared for every risk identified. This Risk Register was updated every month with current impacts, probabilities and response strategies. The latest Risk Register identifies 17 major risks.

[redacted]

Some of the major risks identified in the Risk Register, which could not be mitigated or avoided, are listed here:

1. Several NFWs or mini Outages were required to execute the field work, which were not easy to get. This risk was identified in the initial stage but could not be resolved in time.

2. The Risk Register identifies that permits and work authorization availability could become an issue. To mitigate it, there was some schedule float created in P5/P6 schedule but it was not resolved efficiently.

3. Due to limited field walk downs, most of the design was prepared based on assumptions and information/photos provided by Fuel Handling. This risk was identified and accepted in the Risk Register.

4. Coordination among many stakeholders was identified in the Risk Register but no formal strategy was prepared. Key stakeholders during installation were – three Design Agencies, Field Engineering (Electrical and Civil), OPG Design Team Lead (DTL), Modifications Team Lead (MTL), System Responsible Engineer (SRE), Operations and Maintenance (FH), Inspection and Maintenance Services (IMS), Supply Chain and Radiation Protection.

Some of the Risks which were not identified in the Risk Register during the initial stages of the project are listed here.

1. The 2009 VBO was a good opportunity to execute the field work. Management also planned accordingly but design and material were not ready. This sudden change in schedule was not identified in the Risk Register.

2. Project scope changed significantly just before the field execution commenced, which impacted cost significantly. The DRD and DI projects had been completely designed and material had been procured. Before installation began, both projects were dropped from the scope due to several reasons. This risk was not initially identified.

Despite several known and unknown risks, the project was completed with the allocated contingency in cost and float in the schedule.

4.6.2 Lessons Learned

LL 4.6.1: Risk Management Plans should be developed early in the project lifecycle in order to guide risk mitigation. Earlier identification of risks, such as schedule unpredictability, could have helped reduce the effect of these risks.

LL 4.6.2: Substantial effort should be spent on correctly identifying potential risks. Many major and foreseeable risks were not correctly identified which lead to cost, schedule and scope management issues. For example, the risk of not completing experimental work, such a DI and DRD, should be an identified risk in order to mitigate the effects of the scope reduction on other ongoing work.

4.7 Contract & Procurement Management

4.7.1 Overview

In the early stages of project 16-31438 it was identified that the project modifications would target a VBO installation window in 2009. This required expediting the design for DI, DRD and VSS which lead to a design agency sole source contract with GE. Sole sourcing was chosen because GE possessed FH system expertise, wiring drawings were controlled by GE and this was the most expeditious means of meeting the VBO installation window.

Later in the project, after the VBO window passed, a competitive bidding strategy was used for the design of VSS release 4. SNC-Lavalin was chosen as the design agency which resulted in significant cost savings. Having two different design agencies created some problems because they were both updating the same design documentation for overlapping design proponents for VSS release 3 and 4.

A competitive bidding process was used for the construction contractors. This resulted in EMC winning the contract for electrical installation and Black and McDonald winning the contract for civil work. A decision was made to use the same contractors for a number of releases due to the overhead involved with training and equipment familiarization.

4.7.2 Contract Management Plans

As Per FIN-MAN-CM-001, a Contract Management Plan (CMP) is required to record planning and post-award decisions that shall be used by OPG to monitor the contracts. It is both a communication and control tool. It can become a key factor in dispute and event resolution.

There were no CMPs prepared for VSS release 1 and release 2.

The following two CMPs were prepared as outlined in FIN-MAN-CM-001 for VSS release 3 and release 4 field installation work:

- CMP for Electrical Work performed under PO # 00195631
- CMP for Civil (Scaffold) Work performed under PO # 00176088

Under these two CMPs the following items were clearly identified:

- Scope of the Contracts, Contract Strategy, Responsibility Matrix (OHSA), Risk Management, Schedule and Communication Plan, Dispute Resolution, Acceptance Plan, Change Management, Payment plan

4.7.3 Lessons Learned

LL 4.7.1: A competitive bidding process should be used to avoid the costs associated with sole sourcing. If time pressures had not been present at the beginning of the VSS project, the use of competitive bidding could have resulted in significant cost savings.

LL 4.7.2: Projects containing multiple releases with overlapping design proponents should only use one design agency. If the releases don't contain completely independent designs, the same design agency should be used to avoid configuration management issues.

LL 4.7.3: Projects containing multiple releases should use the same construction contractor when possible. This reduces the overhead required for training and equipment familiarization.

4.8 Quality Management

A detailed Quality Management Plan was prepared under the PEP in compliance with CSA N286.2 standards.

Design Agencies complied with Design Agency Interface Agreement (DAIA) D-DAI-63578-0001 to produce the design packages.

All procurement activities were performed in accordance with N286.1-00 and as per N-PROC-MP-0098. Material which did not meet OPG requirements were documented and acted on as per OPG OSD&D process under N-PROC-MM-0021.

All Construction activities were performed in accordance with the requirement of CSA N286.3 program. Contractors performed construction work per approved OPG procedures and under OPG Certificate of Authorization. Online work scheduling process as outlined in N-PROC-MA-0022 were followed to schedule the work order tasks. Quality Surveillance of contractor work was conducted per N-PROC-AS-0074.

Inspection and Test Plans (ITP) were prepared and executed in field as per N-INS-01983.1-10001. All commissioning activities were performed by OPG Control Maintenance department as per CSA N286.4

4.9 Communication Management

There was no formal Communication Management Plan prepared. Regular meetings and teleconferences were organized throughout the project. These meetings were very useful in tracking the issues and resolving them in timely manner. Monthly project update reports were also prepared.

Regular and effective communication was attempted to coordinate with FH operations and maintenance to schedule the field work during No Fueling Windows (NFW). This communication improved in the later stages of the project which ultimately lead to the mini outages used to finish installations.

Meeting minutes and reports were originally saved but were eventually lost over time. This was discovered when CPIR interviewees attempted to retrieve this information.

4.9.1 Lessons Learned

LL 4.9.1: A communication management plan should be developed early in the project lifecycle. This would ensure the right people were receiving the right information at the right time. It would also help communication between other project teams working on the same system in parallel.

LL 4.9.2: Communication between the project team and station operations and maintenance is necessary to successfully complete field installations. Cooperation between the various stakeholders was necessary to get the schedule commitments.

LL 4.9.3: OPG needs a proper document repository and versioning system to accommodate working documents. Passport / Asset Suite and shared folders are not very useful in this area. This would help avoid the loss of important project documentation.

4.10 Resource Management

4.10.1 Project Organization

Resource management for this project became very challenging due to the lengthy project duration (2004 - 2012). The executing organization for the original project was Design Projects (DP). Resourcing issues resulted in no progress being made on a number of the original 12 initiatives between 2004 and 2006.

When project 16-31438 was started, the initial quotes from GE for the design of VSS were rejected because they were much higher than expected. At the end of 2007, the Fuel Handling organization took control of the MTL and FTL roles for the VSS scope of work.

At the time of the phase 2 full release BCS in early 2010, DP re-acquired the execution of the VSS work due to the soaring project costs. VSS was the only item remaining in the project scope. VSS release 1 and 2 were designed and installed. VSS release 3 design was done and installation planning was in progress. DP then went to a competitive bidding process for the design of VSS release 4. The contract was awarded to SNC-Lavalin while the previous 3 releases had been completed by GE.

The project manager, project leader and MTL roles were filled by DP throughout the project with the exception of the span of time FH provided the MTL for VSS. The DTL role was filled by Projects Design. The design agency was GE for DI, DRD and VSS releases 1, 2 and 3. SNC-Lavalin was the design agency for VSS release 4. No dedicated support was available from the work control department when permits and work authorization were needed for field execution.

FH project sponsors (SRE, operations and maintenance) should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.

Table 4.5: Project Executing Organization

Project	Time	DI	DRD	VSS
16-38451	2004-2006	DP	DP	DP
16-31438	Dev BCS (May 2007)	DP	DP	DP
	Partial BCS (Nov 2007)	DP	DP	FH
	Phase 1 BCS (Jan 2009)	DP	DP	FH
	Full BCS (Jul 2010)	-	-	DP

Note: DP = Design Projects; FH = Fuel Handling

4.10.2 Project Team Turnover

Throughout the project, roles and responsibilities changed hands a number of times. The project manager changed, the project leader changed twice, there were at least four MTLs and four DTLs. The project stakeholders, such as FH SREs, also changed. Based on stakeholder feedback, turnovers weren't always well managed which lead to extra time being spent by the incoming staff to get up to speed.

Two different design agencies (GE and SNC-Lavalin) were used which created delays and conflict because they were updating the same design documents in parallel. Although competitive bidding resulted in a lower cost, the overlapping project proponents for VSS release 3 and 4 caused some problems.

Having a consistent project team familiar with the project history and structure could help the project team to consistently meet the schedule. However, with a project such as this one spanning 8 years, it would have been difficult to maintain a consistent project team.

4.10.3 Lessons Learned

LL 4.10.1: Resources need to be correctly identified early in the project process. Under resourcing resulted in delays between 2004 and 2006 which added extra time pressure to meet VBO installation targets.

LL 4.10.2: Project team member turnover should be kept to a minimum. Turnovers take time and valuable information is easily lost. It takes time to become familiar with a project and this caused schedule and cost delays. Essential project controls such as accurate record keeping must be in place to assist project turnover.

LL 4.10.3: Projects should not change executing organizations. The VSS executing function went from Design Projects to FH and then back to Design Projects. This high level transition affects smooth project execution.

LL 4.10.4: The project team member turnover process needs to be improved. Information and expertise was lost in transition. Stakeholders identified that turnovers weren't always well managed during this project, leading to extra time having to be spent on getting up to speed.

LL 4.10.5: When executing a number of related projects in parallel, available resources must be considered as a project constraint. The scarcity of resources impacted the cost and schedule of the projects.

LL 4.10.6: FH staff should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.

4.11 Project AFS and Closeout

4.11.1 Available for Service / Operations Acceptance

The FHPT capital improvement project was declared available for service through operations acceptance on November 30th, 2011, just in time to meet the project AFS milestone. There are still some cameras that aren't fully functional. Four final AFS documents were signed (see Table 4.6). There were 59 outstanding action tracking items related to the project at the time of AFS (see Appendix B).

Table 4.6: Final AFS Declarations

Master EC	Design ECs	Description	AFS Date
96905	98730, 98518, 98519	Release 1	2011-11-30
96905	98520, 98521	Release 2	2011-11-30
96905	101353, 101352	Release 3	2011-11-30
96905	103382, 103383	Release 4	2011-11-30

Operations Acceptance Declaration was used rather than Available for Service Declaration. Operations Acceptance does not require acceptance from all main stakeholders, just the MTL and operations manager. A project of this magnitude would normally follow the AFS declaration method.

4.11.2 Project Closure

The project closure report [R-11] was issued on November 2nd, 2012, just in time to meet the project closure milestone. The final actual cost was $16.12 M which was lower than the phase 2 full release estimate of $16.16 M which included [redacted]M of contingency. The project closure date was October 31st, 2012 which is one month earlier than the milestone date. Based on the project performance metrics, the project appears to have been a success. CPI is measured against the final approved release (before contingency) plus any contingency released through approved PCRAFs and SPI is measured against the final approved BCS. This does not give a true indication of performance looking back at a project.

A project Lessons Learned document [R-12] was issues on January 16th, 2013 shortly after the CPIR process began. The CPIR report will be prepared by the end of March 2013, thus closing the loop on the entire project. These were deliverables mentioned in the phase 1 full release BCS to be completed under the phase 2 work but the project was closed before their completion.

4.11.3 Lessons Learned

LL 4.11.1: Project milestones should not be declared complete if there are outstanding actions and deliverables. This project was declared AFS with 59 outstanding action tracking items and closed with outstanding deliverables. Outstanding issues may not be addressed in a timely manner due to lack of priority and funding if a project has been closed.

LL 4.11.2: Major projects should be declared available for service through the AFS declaration and not the Operations Acceptance Declaration. With the number of outstanding actions, a conservative decision should have been made and all stakeholders should have agreed to and signed the declaration.

LL 4.11.3: Project closure reports should provide a more accurate look at project performance metrics. Using approved changes as the baseline for final reporting does not give a true indication of overall project performance.

5.0 PROJECT OUTCOMES

5.1 Effectiveness of Final Product in Meeting Original Business Need

The phase 2 full release BCS was approved on July 29th 2010. Section 7 of the BCS contains four measureable parameters to be evaluated as part of the CPIR in order to establish the effectiveness of the final product in meeting the original business need. The required measurable parameter is the avoidance of unit de-rating through improved PT surveillance. Table 5.1 summarizes the measureable parameters in the full release BCS.

Table 5.1: Full Release BCS Measureable Parameters

2010 Full Release Phase 2 CPIR			
Measurable Parameter	**Baseline**	**Target Result**	**How measured & by Whom?**
1. avoid derating thru improved PT surveillance	1. Temp & non-repairable PT VSS is failing & does not cover entire PT	1. provide permanent & maintainable VSS with 90% increase in surveillance area resulting resulting in improved FM availability	1. % visibility coverage of PT during normal ops with VSS alone; reduced operator dose [measured by FH-Technical (SRE)]
2. avoid derating thru improved PT surveillance	2. VSS failing which reqs deviation request for Ops procedures	2. uninterrupted surveillance of fuelling operations	2. camera availability [measured by FH-Technical (SRE)]
3. avoid derating thru improved PT surveillance	3. FFAA bay camera does not cover reqd view of manual ops in ancilliary ports	3. 90% increase in surveillance coverage of manual operations in FFAA ancillary ports	3. % of visibility coverage of ancillary ports [measured by FH-Technical (SRE)]
4. project executed within approved budget & schedule	not applicable	4. key milestones met and project cost within approved release	4. CPI; SPI; milestone adherence [MTL, Design projects to measure]

5.1.1 Parameter 1 – Visibility of the Power Track System and Reduced Operator Dose

The full release BCS states the following measurable parameter:

> *"% visibility coverage of PT during normal operation with surveillance system alone. Reduced operator dose."*

This parameter measures the targeted result of:

“a permanent and maintainable surveillance system with 90% increase in the surveillance area resulting in improved FM availability”

The design manual for the closed circuit television system (NK38-DM-60260) was revised on January 28th 2012 (R001), two months after the AFS date of November 30th 2011. It is unclear how the final design can meet the intent of the design manual, when the design manual was issued after the AFS date.

Reduced Radiation Exposure

The revised design manual states the following under “Functional Requirements”

1. To monitor processes and activities in areas normally inaccessible due to high radiation fields.

2. To reduce radiation exposure of supervisory personnel when monitoring routine maintenance or emergency repairs.

3. To view in the training room, fuelling operations, etc for the training of operating personnel.

Point number two mentions a reduction in radiation exposure, however it does not quantify the reduction by stating what the current radiation dose is, and what the new reduced target must be.

The full release BCS does not quantify dose reduction in any way (stating dose levels before the start of the project and target dose reduction after). The project design package does not contain any calculations or Dosimetry Management System (DMS) audits for radiation dose received by the worker before or after the camera system installation. As a result, compliance with this measure is inconclusive based on the project documentation available.

Performance Requirements (Percent Coverage)

The revised design manual states the following under “Performance Requirements”

“The system shall comprise of CCTV cameras, monitors, control unit, key board with joystick, network of cables, receptacles for cameras and receptacles for monitors/control units.

The system shall be flexible and shall provide extensive coverage. The system shall have capability to expand CCTV monitoring capability in future. Electrical installation shall meet Ontario Electrical Safety Code.

All view coming to the Main Control Room (MCR) shall be recordable as required basis. “

The performance requirements do not specify an increase in camera surveillance area. Full Release BCS parameter 1 states a 90% increase in surveillance area, however it does not state a baseline value on the existing system. The design package for the surveillance system does not contain any calculations for camera surveillance area before or after the project is complete.

Table 003 in section 2.0 of the camera system design manual summarizes qualitative detail on coverage area for the new system and in shown below:

Table 5.2: Camera Coverage Areas in Design Manual

Section	Coverage Requirements
2.2.1.1 Fuelling Machine and Transport Trolley	1. Snout locking mechanism during homing and locking in reactor channel or FFAA ports. 2. Catenaries during fueling machine transversing 3. Trolley mounted auxiliaries, gauges, counters etc 4. Reactor Area Bridge Drive. 5. Reactor face 6. Indicator of TMM Magazine position providing information on what type of component is being installed in each position (only during outage TMM use) 7. Substitute view of partial power track component inspection defined under section (only during outage or other abnormal condition when Common Service Area (CSA) cameras cannot cover entire power track component due to Trolley movement restriction) 8. Cover entire Trolley area by a hand held camera connecting to the CCTV system to be viewed remotely from MCR.
2.2.1.2 Central Service Area	1. End drum, end drum wheel assembly and end drum support assembly 2. Intermediate roller, end plate assembly, endplate wheel assembly and pillow block bearing surface. 3. Inner side of C channel for any debris, grooved wheel round bar and flat wheel bar. 4. Chain sag, outside side chain pins, carrier bar, outside carrier bar pins, cable, cable riser and coupling frame.
2.2.1.3 East and West Reception Bay	1. Camera to provide view of the ancillary port. The camera shall view the personnel working on the ancillary port. This shall be available to be viewed from the MCR panel. 2. Camera shall provide view of reception bay Irradiated Fuel Discharge Mechanism (IFDM).
2.2.1.4 Wet Flask Handling Area	1. A camera shall be provided in the wet flask handling area for viewing irradiated fuel flask handling and shipping operation.

The project closure report states that the camera project components were installed in Section 1.0 “Deliverables and Milestones”. The report makes no mention of meeting the camera system performance requirements mentioned in the design manual (see Table 5.2). With no evidence that the installed system meets the coverage requirements in the design manual, and no basis for comparison available to establish the specific coverage increase requirement of 90%, exact compliance with parameter 1 (surveillance area) is inconclusive.

When interviewed, FH operators considered the increase in camera coverage on the new surveillance system to be negligible. Operators do not feel that the new surveillance system will reduce the possibility of another 2004 incident.

5.1.2 Parameter 2 - Camera Availability

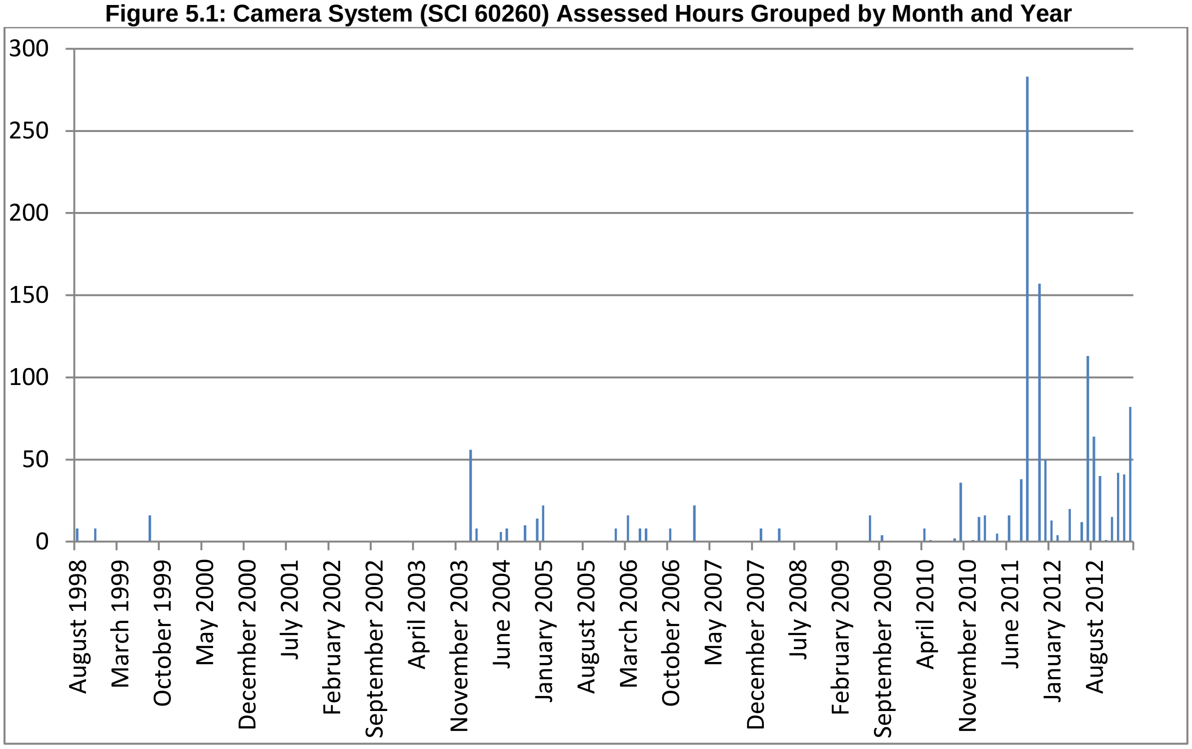
“Camera availability” is stated as a measurable parameter for increased fuelling operation surveillance. The increased surveillance avoids deviation from operating procedures.

The full release BCS does not provide a baseline value for availability over previous years. The project design documents do not provide availability calculations for the previous system. In this report, two different approaches are used to determine if there has been a change in system availability after project installation and AFS November 30th 2011:

5.1.2.1 Quantitative Approach

A quantitative approach is used to attempt to numerically describe equipment availability. If the camera system is unable to perform its function, corrective and/or deficient work will begin to appear. This approach involves an assessment of all Passport work orders entered into the system under the camera system SCI 60260. The camera system work order tasks are filtered to include only corrective and deficient work order types. The assessed hours for all work orders are then grouped and totalized by calendar month and year. Figure 5.1 shows a graph of all assessed hours for SCI 60260, grouped by calendar month and year.

Figure 5.1: Camera System (SCI 60260) Assessed Hours Grouped by Month and Year



Although the assessed hours increased slightly between 2004 and 2010, there is a noticeable increase in the assessed hours around November 2011 (the time the system was installed), and all throughout 2012 and 2013. The year 2004 had the largest number of corrective work order hours assessed prior to the installation of the new surveillance system. The total hours in 2011 and 2012 are three to five times larger than 2004. These results indicate a large amount of corrective work at installation, and continuing while in service. Table 5.3 is a summary of the data in Figure 5.1, grouping all work order tasks by calendar year.

Table 5.3: Camera System (SCI 60260) Assessed Hours Grouped by Year

Year	Total Assessed Corrective / Deficient Hours
2013	123
2012	324
2011	580
2010	48
2009	20
2008	16
2007	22

2006	48
2005	22
2004	102
1999	16
1998	16

There is more corrective / deficient work for the camera system assessed in 2013 and 2012 than any year previous to the installation year (2011). The assessed hours in 2013, have already exceeded one third of the previous year's total in January and February alone.

The increase in assessed hours in 2012 / 13 suggests the availability of the new camera system has decreased. It is possible that the increase in assessed deficient / corrective work hours is due to a work-in period for the system. As such the quantitative approach by itself is not sufficient to determine system availability.

5.1.2.2 Qualitative Approach

The qualitative approach to describe equipment availability looks at system documentation such as heath reports and work order task instructions in order to try to explain the results obtained in the quantitative approach.

System Health Report

System health for the VSS is tracked in the System Health Report (SHR) for the Trolley and Power Track system (SCI 35710). Problems with the camera system appear in Problem ID 5 (system unique indicator #3) of the latest system health report available as of Q1 2013. Table 5.4 summarizes the deficient work orders for the camera system:

Table 5.4: Work Orders Tracked in the SHR

WO / WR	Deficiency
W/R 869100 (W/O 2861819)	Poor image quality on T(3 and T(4 trolley cameras (VC 3 and VC4) .
W/O 2694182	No signal from VC 31, 32, and 37. Control maintenance has determined that there is no signal going to the control room, or to the intermediate panel. Unit 2 outage required for troubleshooting / replacement work.
W/O 2825316	Cameras VC 26 and VC 29 were replaced during the D1231 outage but still do not function. Control maintenance to perform troubleshooting activities.
W/O 2745944	Trolley 2 camera (VC2) found to be defective. Control maintenance has replaced the defective camera, and has rebuilt the defective camera.
W/O 2805413	Trolley 6 camera (VC6) has no signal in the main control room. Control

	maintenance has swapped the camera on Trolley 6 with a working unit on Trolley 5, with no results. Cable troubleshooting work is still outstanding.
W/R 869102 (W/O 2501272, 2863785)	Trolley 5/6 power track camera has been knocked off its mounting. New brackets need to be installed.

Work orders 2861819 and 2745944 are for defective trolley cameras. Consultation with the camera system SRE and the installation OEM has identified two contributing factors for these work orders.

The original trolley mounted cameras (VC1 through VC6) have a design flaw located at the base of the camera unit. The design flaw produces a gradual degradation of the internal cabling at the base of the camera, gradually reducing the image quality. Control maintenance staff has installed replacement parts to correct the design flaw on all stocked spare trolley cameras.

The trolley mounted cameras provide a large viewing area for the operator; however the cameras are mounted in a location that will receive a large dose from the reactors while in service. Although the cameras fail frequently (less than one year of service), replacement cameras are stocked on site. The cameras can be replaced with the reactor units online, the trolley parked inside an FFAA, and with the shield door closed, minimizing dose to the worker.

The failure of the trolley mounted cameras VC3 and VC4 do not represent a concern for system availability. The design flaw has been corrected on all stocked spare units. The failures are equipment lead-in problems that have been corrected.

W/O 2501272 / 2863785 is for a camera that has been physically damaged while in service. The cause of the damage is not yet known, and cannot be attributed to a system availability issue.

W/O 2825316 is for the troubleshooting and / or replacement of two power track cameras (VC26 and VC29). Both cameras stopped working immediately after they were replaced during the D1231 outage. This represents a concern for system availability. Additional troubleshooting work is required to determine the fault and restore availability.

W/O 2694182 requires additional troubleshooting work during a unit 2 outage. Cameras VC31, 32, and 37 were not functioning properly when the surveillance system was commissioned. Additional troubleshooting work is required for the cabling from the camera to the nearest wall-mounted junction box in containment. The cameras must remain out of service until the troubleshooting work can be completed as part of a unit 2 outage. This outstanding corrective maintenance work reduces system availability.

W/O 2805413 is to investigate a loss of video signal from the trolley mounted camera on trolley 6. Continued troubleshooting work is required between the trolley mounted camera and the intermediate amplifier junction box inside containment. The trolley mounted camera on trolley 6 is unavailable.

Of the six items tracked in the Q1 2013 SHR for the Trolley and Power Track System, two items are not a concern for system availability. The remaining four items are a reduction in system availability.

DVR failure

The camera system Digital Video Recorders (DVRs) record video signals from all cameras. The recording is triggered by motion or by the operator (using an built in user interface). There are a total of three DVRs in the system (one per trolley). The DVR module on T(3,4 has failed after less than 2 years of service (WO 2910661). The DVR is not subject to any environmental or radiation hazards. Although the camera system design manual (NK38-DM-60260) does not provide an in-service lifetime, the DVR units are an essential component, allowing the SRE and / or operator to play back historical video to look for equipment defects that may lead to another failure. This represents an availability concern, inhibiting the use of the camera system to help prevent a recurrence of the 2004 event.

Non-Standard Operating Condition

Operating manual NK38-OM-35700 Section 4.3.4 (3) states that a trolley cannot operate in coarse drive if two v-groove wheel cameras have failed or if two flat wheel cameras have failed. One power track v-groove camera and one flat-wheel camera have failed on the T(5,6 power track surveillance system (W/O 2825316, VC26 and VC29). If one more power track wheel camera fails on T(5,6, (VC39 or VC36) the trolley will be restricted to fine drive, reducing its speed by a factor of 12.5 (maximum 16 ft/min as opposed to 200 ft/min), reducing fuel delivery rates on unit 3 and unit 4 by at least 68%.

The failure of the power track cameras on trolley 5,6 reduces system redundancy, and is a loss of system availability.

Blind Roller Inspection

Work order 2875548 is for an operator inspection of the T(1,2 power track rollers every 13 weeks. This work is required as a compensatory measure against failed power track cameras VC31, 32, and 37. The work order instructs the operator to enter the vault to look for damaged or dropped rollers. The reduced availability of the power track cameras on T(1,2 increases operator dose levels, contrary to the original design intent of the system.

Conclusion

The quantitative review has shown an increase in assessed hours for corrective and deficient maintenance. A qualitative review of corrective work orders in the system health report has revealed that four out of the six deficiencies tracked in the SHR are to address system availability problems. The recent failure of the system 3 DVR reduces availability of essential historical video. Power track camera failures have reduced surveillance system redundancy, increasing operator dose as a result of compensatory measures. After installation and acceptance of the surveillance system in November 2011, the surveillance system availability has reduced, resulting in an increase in corrective maintenance workload, increased operator dose, and a loss of surveillance redundancy potentially reducing fuel delivery rates.

5.1.3 Parameter 3 - Visibility of the FFAA Ancillary Ports

Similar to parameter 1, there is no evidence that the installed system meets the qualitative coverage requirements in the design manual, and no basis for comparison available to establish the specific coverage increase requirement of 90%. Exact compliance with parameter 3 is inconclusive.

5.1.4 Parameter 4 – Project Performance Metrics

The project closure report states that the CPI is 1.0 and the project was closed 30 days ahead of schedule indicating that the SPI is also 1.0. All key milestones were also declared completed either ahead or on schedule.

5.2 Training

Operator training was not completed for the FHPT camera upgrades project. Control maintenance training was completed in November and December of 2012 (WO 1924965). The equipment OEM provided five sessions with detailed maintenance and troubleshooting instructions for control maintenance and technical support staff.

5.3 Lessons Learned

LL 5.1.1: Performance parameters must be specific to the business need and project objectives, be measurable and have a measured baseline available. The performance requirements in this project demonstrate camera availability and reduced dose to the operator. It is not clear how these measures will show that the camera system is working to prevent a recurrence of the 2004 incident or to improve system reliability. The following performance parameters could have been used instead and would show that the surveillance system is working, and that it meets the original business need of the project:

- Number of full-length power track roller / chain inspections per year.
- Number of reactor face inspections per year.
- System availability as determined by a measurable parameter, such as:

- hours of saved DVR video per fuelling run for the power track cameras
- hours of saved DVR video per fuel push for the FFAA cameras

LL 5.1.2: Performance parameters must have a measurable baseline in place. The design package must include reports and / or calculations that prove that the design meets the performance parameters. Project close-out documents must include checklists, measurements, or calculations that clearly show how well the installed equipment meets the performance parameters.

LL 5.1.3: Provide training for all stakeholders affected by the project. Ensure that training is added to the project scope and that resources are scheduled as part of project execution.

6.0 SUMMARY OF LESSONS LEARNED

Table 6.1: Summary of Lessons Learned

LL Ref.	Description
LL 3.2.1	At the start of a project, the problem definition and Business Need statement should be defined in the most specific terms possible, allowing specific solutions to be identified and prioritized based on the expected benefit attributable to each solution.
LL 3.2.2	A thorough review of the alternatives should be conducted in the early project phases (initiation phase, early definition phase) to review their implementation practicality and requirements, including the cost and schedule requirements. The evaluation of the alternatives should involve all stakeholders (design, operations, maintenance, OEM, etc.) and should consider the project-specific constraints such as the limited availability of No Fuel Windows in this case.
LL 3.4.1	When several major scopes of work are associated with reducing a financial risk to the company, the outstanding (remaining) financial risk used in the financial evaluation in successive business cases should be revised to reflect the outstanding (non-retired) portion of the financial risk, as appropriate.
LL 3.4.2	It is important that the inputs and assumptions used in the financial evaluations, or NPV calculations, for the base case and alternatives be vetted with all stakeholders to ensure that realistic and conservative assumptions are used resulting in the best possible economic data being provided for the decision-making process.
LL 4.1.1	Project charters should not identify the specific solutions including specifying the design agency to be used for the proposed modifications. Other options should be pursued rather than jumping to a sole-sourcing design solution that could be more costly than other options.
LL 4.1.2	The problem definition and business need statement should be as clear and specific as possible from the beginning of the project. In this case it is very general and it is difficult to relate the proposed solutions to the business need. A general problem statement leads to scope development and prioritization issues later in the project lifecycle.
LL 4.2.1	Project Execution Plans (PEP) should be developed in parallel with the BCS. The PEP helps document, monitor and control various key project management areas. The BCS should be a summary of much of the information outlined in the PEP.
LL 4.2.2	Project Execution Plans should contain plans for all project management areas. Project 16-31438 had many scope, cost and schedule management issues. The existence of a proper PEP could have helped mitigate the risks.
LL 4.2.3	Proper turnover and document management processes need to be followed for OPG projects to ensure no loss of information. A PEP was developed in 2008 but was lost and never approved. Information from this PEP could not be used for the development of the actual approved PEP.
LL 4.3.1	Projects with multiple initiatives need to have their scope prioritized to ensure effort is being focused on key areas and areas that need to be completed before others can begin. A Scope Management Plan could have helped document the relationship between initiatives and help prioritize the larger number of initiatives.
LL 4.3.2	Projects consisting of a large number of initiatives should be grouped into a number of separate projects based on the business need and objective they are trying to achieve. This would allow the proper amount of resources to be assigned to each project to ensure progress is being made on all initiatives.
LL 4.3.3	When multiple projects exist for a system, the impact of one project must be assessed on the other projects. Due to several parallel FHPT projects, one project's impact on other projects

	was not realized. After the roller endplate modification, the performance of the modification should have been assessed before starting the proposed modifications (DRD and DI system) on the same system.
LL 4.3.4	Projects should not contain initiatives requiring design input from the completion of another project. This was the case for project 16-38472, OM&A FHPT Improvement, as shown in figure 2.1. Those initiatives could also be a second phase of the preceding project, only to be executed based on the results of the design inputs. This would reduce effort and money spent on initiatives that were ultimately cancelled due to the cancellation of DI.
LL 4.3.5	Projects resulting from a major station event should initially be reviewed by a third party to ensure the initiatives are feasible and aligned with the stated business need. The OEM should be contacted immediately for input. Emotions tend to be running high after a significant event and an independent look at the proposed solutions should be completed. Six of the twelve initiatives identified in 2004 were cancelled as a result of an OEM assessment received in 2009, five years after the projects began, resulting in significant cost write-offs and lost effort.
LL 4.4.1	Time pressure should be avoided in order to follow project management best practices. Targeting VBO installation expedited the design phase of the project which resulted in the use of sole sourcing. This had an impact on overall project cost.
LL 4.4.2	Projects requiring field installation should attempt to have their schedule pre-negotiated and committed to by operations and maintenance. However, the use of NFWs for project installations is ineffective as these windows have a tendency to move and cannot be pre-negotiated.
LL 4.4.3	Fuel Handling projects requiring NFWs for installation, should explore the use of FH mini outages to complete the work. More work can be executed because of the reduction in overhead involved with starting work each time. The mini outages should be planned and committed to like a unit outage.
LL 4.4.4	Projects executed in areas with high radiation and limited accessibility should have adequate schedule float in order to meet installation milestones. Due to unexpected breakdown maintenance issues, most of the NFWs were taken away from this project.
LL 4.4.5	When executing project installation work, extra resources should be assigned for timely application of permits and work authorization.
LL 4.5.1	The CPIR team recommends that project cost performance for project closure reports should also show the deviation from the summary of estimate before contingency. CPI based on the most recently approved release is used for project cost management but the CPIR team feels that this does not give an accurate representation of overall cost performance looking back at a project.
LL 4.6.1	Risk Management Plans should be developed early in the project lifecycle in order to guide risk mitigation. Earlier identification of risks, such as schedule unpredictability, could have helped reduce the effect of these risks.
LL 4.6.2	Substantial effort should be spent on correctly identifying potential risks. Many major and foreseeable risks were not correctly identified which lead to cost, schedule and scope management issues. For example, the risk of not completing experimental work, such a DI and DRD, should be an identified risk in order to mitigate the effects of the scope reduction on other ongoing work.
LL 4.7.1	A competitive bidding process should be used to avoid the costs associated with sole sourcing. If time pressures had not been present at the beginning of the VSS project, the use of competitive bidding could have resulted in significant cost savings.
LL 4.7.2	Projects containing multiple releases with overlapping design proponents should only use one design agency. If the releases don't contain completely independent designs, the same design agency should be used to avoid configuration management issues.
LL 4.7.3	Projects containing multiple releases should use the same construction contractor when

	possible. This reduces the overhead required for training and equipment familiarization.
LL 4.9.1	A communication management plan should be developed early in the project lifecycle. This would ensure the right people were receiving the right information at the right time. It would also help communication between other project teams working on the same system in parallel.
LL 4.9.2	Communication between the project team and station operations and maintenance is necessary to successfully complete field installations. Cooperation between the various stakeholders was necessary to get the schedule commitments.
LL 4.9.3	OPG needs a proper document repository and versioning system to accommodate working documents. Passport / Asset Suite and shared folders are not very useful in this area. This would help avoid the loss of important project documentation.
LL 4.10.1	Resources need to be correctly identified early in the project process. Under resourcing resulted in delays between 2004 and 2006 which added extra time pressure to meet VBO installation targets.
LL 4.10.2	Project team member turnover should be kept to a minimum. Turnovers take time and valuable information is easily lost. It takes time to become familiar with a project and this caused schedule and cost delays. Essential project controls such as accurate record keeping must be in place to assist project turnover.
LL 4.10.3	Projects should not change executing organizations. The VSS executing function went from Design Projects to FH and then back to Design Projects. This high level transition affects smooth project execution.
LL 4.10.4	The project team member turnover process needs to be improved. Information and expertise was lost in transition. Stakeholders identified that turnovers weren't always well managed during this project, leading to extra time having to be spent on getting up to speed.
LL 4.10.5	When executing a number of related projects in parallel, available resources must be considered as a project constraint. The scarcity of resources impacted the cost and schedule of the projects.
LL 4.10.6	FH staff should play a more active role in FH projects being executed by the projects organization. Stakeholder interviews revealed that projects staff were unfamiliar with FH systems and FH technical staff were sometimes unavailable to help.
LL 4.11.1	Project milestones should not be declared complete if there are outstanding actions and deliverables. This project was declared AFS with 59 outstanding action tracking items and closed with outstanding deliverables. Outstanding issues may not be addressed in a timely manner due to lack of priority and funding if a project has been closed.
LL 4.11.2	Major projects should be declared available for service through the AFS declaration and not the Operations Acceptance Declaration. With the number of outstanding actions, a conservative decision should have been made and all stakeholders should have agreed to and signed the declaration.
LL 4.11.3	Project closure reports should provide a more accurate look at project performance metrics. Using approved changes as the baseline for final reporting does not give a true indication of overall project performance.
LL 5.1.1	Performance parameters must be specific to the business need and project objectives, be measurable and have a measured baseline available. The performance requirements in this project demonstrate camera availability and reduced dose to the operator. It is not clear how these measures will show that the camera system is working to prevent a recurrence of the 2004 incident or to improve system reliability.
LL 5.1.2	Performance parameters must have a measurable baseline in place. The design package must include reports and / or calculations that prove that the design meets the performance parameters. Project close-out documents must include checklists, measurements, or calculations that clearly show how well the installed equipment meets the performance parameters.

LL 5.1.3	Provide training for all stakeholders affected by the project. Ensure that training is added to the project scope and that resources are scheduled as part of project execution.

7.0 CONCLUSIONS AND RECOMMENDATIONS

In accordance with project management governance and measures, the FHPT Capital Improvement project was deemed to be successful in terms of cost and schedule when compared to the Phase 2 Full Release Business Case Summary (BCS) approved in 2010. A surveillance system has been put in place, which allows remote inspection and real-time monitoring of the FHPT. However, not all VSS cameras are fully functional and outstanding actions still exist.

When looking back at the project, the CPIR team concluded that overall cost performance was not acceptable and scope management and implementation during the project was not well executed. The Partial Release BCS approved in late 2007 forecasted the final project cost to be $9.3 M and included three modifications (DI, DRD and VSS). The Phase 1 Full Release BCS approved in early 2009 forecasted the final cost of the project to be $17.38 M for the three modifications. In mid 2009, five years after the initial event, OPG requested a project scope assessment from the Original Equipment Manufacturer (OEM). The assessment made a number of recommendations to improve FHPT reliability, none of which included a DRD or DI system.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of the project. This was a result of the OEM assessment leading to a joint review by Fuel Handling and Design Projects. The joint review determined that there was low value for money in proceeding with DI and DRD.

The Phase 2 Full Release BCS in 2010 forecasted the final cost of the project to be $16.16 M, which is approximately $1 M less than the previous BCS, but the scope of the project had been reduced to the VSS modification.

The CPIR team conducted a thorough assessment of project management practices, BCS quality and project outcomes. Project documentation was reviewed and project stakeholder interviews were conducted. Lessons learned have been summarized in section 6 of this report. Recommendations based on the key themes of the lessons learned have been documented below.

Recommendation 1: Fuel Handling Mini Outages bring Predictability to Project Installation Schedules

The CPIR team recommends that the use of FH mini outages with committed dates be explored as an alternative to the use of NFWs for project installation work. NFWs have a tendency to move and competing station priorities may result in bumped project work. Resources can then be assigned to project installation work with more certainty, increasing the probability of achieving project schedule and cost estimates.

The FHPT Capital Improvement project attributed cost and schedule delays to the unpredictability of the installation schedule. NFW commitment was difficult to obtain, NFWs moved and proper resources for permit application and work authorization weren't available when installation work was finally executed. The work was eventually executed successfully using FH mini outages.

Recommendation 2: Milestones and Other Time Pressures should not take priority over Project Management Best Practices

The CPIR team recommends that project management best practices should not be sacrificed to meet deadlines. Milestones should not be declared complete when actions to meet the milestone are still outstanding.

The FHPT Capital Improvement project initially targeted installation during the 2009 VBO. Decisions were made based on the VBO time pressure. Relief from outage milestones was required and GE was awarded a sole source contract to expedite the design process. The project was declared AFS through operations acceptance in November of 2011 with 59 outstanding actions in order to meet the project AFS milestone. The project was closed out in November of 2012 to meet the project closure milestone leaving a number of project closure deliverables incomplete, such as the Lessons Learned document and the Comprehensive Post Implementation Review.

Recommendation 3: Major projects resulting from High Profile Events should undergo an Initial Independent Assessment of the Business Need and Identified Alternatives

The CPIR team recommends that a third party assessment be done early in projects resulting from high profile events. After a major station event, emotions are running high and there is an urgency to quickly correct the identified causes. An independent assessment of the proposed solutions would help identify if those solutions are feasible, if they meet the business need and whether the alternative analysis has been thorough including comprehensive stakeholder involvement.

Key stakeholders interviewed described the actions following the 2004 FHPT as a "shotgun" approach, where a number of solutions were identified and pursued through project 16-38451. The feasibility of the solutions was not determined, a value engineering assessment was not done, the OEM was not contacted and the scope was not prioritized. In the end, 6 of the 12 initial initiatives were cancelled.

Recommendation 4: Clear and Specific Problem Definition and Business Need Statement need to be developed at the beginning of a project

The CPIR team recommends that extra scrutiny be placed on the problem definition and business need statement at the outset of the project lifecycle. A clear and specific problem definition linked to root causes is crucial to enable a thorough alternative analysis, scope identification and scope prioritization. All activities throughout the project lifecycle should be continuously checked against the business need to ensure continuity with the problem definition and proposed solution.

The business need for this project was to improve the reliability and performance of the FHPT. This need did not address the root causes determined through the 2004 FHPT event investigation. The generality of the statement resulted in 12 initiatives being identified for project 16-38451 and 6 of the original initiatives were eventually cancelled. The final scope of project 16-31438, VSS, does not address reliability and performance improvement.

Recommendation 5: An approved Project Execution Plan is needed early in the Project Lifecycle

The CPIR team recommends that a thorough project execution plan be prepared and approved during the early stages of a project. A plan should be in place to document, monitor and control all project management knowledge areas to ensure effective project execution.

The FHPT Capital Improvement project was lacking a Project Execution Plan (PEP) until February of 2010. The initiatives under this project were started in 2004 and a PEP should have been prepared at that time to guide initiative progression. The implementation of a plan in 2010 helped bring the project to completion. If it was developed earlier in the project lifecycle, the project could have benefitted in terms of scope, cost, schedule, and risk management. Having proper plans in place could have also helped manage resource and scope relationships between the multiple FHPT projects.

Recommendation 6: Alternatives to Sole Source Contracts should always be explored

The CPIR team recommends that the justification for sole source work be closely scrutinized to ensure that benefits from the competitive bidding process are not lost. GE was chosen as the sole source for the camera system on the basis of their experience with fuel handling technology. There was no technical basis for this decision, as the surveillance system technology is not dependant on any unique aspects of the fuel handling system technology.

The FHPT capital improvement project used a sole source contract with GE to expedite the design phase of the project. VSS Release 4 went to competitive bidding which resulted in significant cost savings. Had this approach been used from the initial stages of the project, final project costs could have been lower.

Recommendation 7: An improved Document Repository and Versioning System is required

Having a proper document control system for working documents is useful for tracking changes and ensuring documentation is not lost. Documentation was lost at various stages of the project. Lost documentation leads to rework and loss of information crucial to decision making. Asset Suite and shared drives are not an effective means of managing working documents.

The FHPT Capital Improvement project CPIR revealed that project documentation was lost a number of times throughout the project lifecycle. An earlier version of a prepared PEP was lost, resulting in rework and not having a PEP approved until 2010. When CPIR interviewees attempted to retrieve project documentation from the shared drive for the CPIR team, they found documentation was missing.

8.0 GLOSSARY

AFS	Available For Service
AISC	Asset Investment Screening Committee
BCS	Business Case Summary
BOE	Basis Of Estimate
CPI	Cost Performance Index
CPIR	Comprehensive Post Implementation Review
DI	Dynamic Instrumentation
DNGS	Darlington Nuclear Generating Station
DP	Design Projects
DRD	Dropped Roller Detection
DTL	Design Team Leader
FEP	Front End Planning
FH	Fuel Handling
FHPT	Fuel Handling Power Track
FTL	Field Team Leader
GE	General Electric
IEV	positive Impact on Economic Value
IF	Irradiated Fuel
LL	Lessons Learned
MTL	Modification Team Leader
NPV	Net Present Value
OEM	Original Equipment Manufacturer
OM&A	Operations, Maintenance & Administration
OPEX	Operating Experience
OPG	Ontario Power Generation
PCRAF	Project Change Request Authorization Form
PEP	Project Execution Plan
PIR	Post Implementation Review
PM	Project Management
PO	Purchase Order
PT	Power Track
QA	Quality Assurance
REIS	Report of Equipment In Service
RMP	Risk Management Plan
RMP	Reactivity Management Plan
SCR	Station Condition Record
SPI	Schedule Performance Index
SRE	System Responsible Engineer
T&M	Time and Material
T(X,Y	Trolley System Identifier (X,Y = 1,2 or 3,4 or 5,6)
TMOD	Temporary Modification
VBO	Vacuum Building Outage
VSS	Video Surveillance System

9.0 REFERENCES

[R-01] “Fuelling Machine Power Track Rehabilitation Project 38451 Charter”, D-PCH-63578-10001, 2004-Sep-14

[R-02] “Fuelling Machine Power Track Rehabilitation Project: 16-38451 Full Release Business Case Summary”, D-BCS-63578-10005, 2006-Mar-09

[R-03] “Project Closure Report F/H Power Track Rehabilitation Project 16-38451”, FIN-FORM-PA-005, 2008-May-02

[R-04] “FH Power Track Improvement – Capital Funded Project 31438 Charter”, D-PCH-63578-10004, 2006-Apr-04

[R-05] “FH Power Track Rehabilitation 16-38472 OM&A 16-31438 Capital – Developmental Release Business Case Summary”, D-BCS-63578-10008, 2007-May-28

[R-06] “FH Power Track Rehabilitation 16-38472 OM&A 16-31438 Capital – Partial Release Business Case Summary”, D-BCS-63578-10009, 2007-Nov-13

[R-07] “Fuel Handling Power Track Modifications – Capital - 16-31438 – Full Release (Phase 1) Business Case Summary”, D-BCS-63578-10010, 2009-Jan-26

[R-08] “Fuel Handling Power Track Capital Improvement Project 16-31438 – Full Release Business Case Summary”, D-BCS-63578-10006, 2010-Jul-29

[R-09] “Approval to Write Off Costs for Project 16-31438”, NK38-CORR-63578-0313360, 2009-Dec-21

[R-10] “Fuel Handling Cable Carrier Condition Assessment”, NK38-IR-0-63578-10001, 2009-Aug-11

[R-11] “Project Closure Report FH Power Track Capital Improvement Project 16-31438”, FIN-FORM-PA-005, 2012-Nov-02

[R-12] “Fuel Handling Power Track Cameras Lessons Learned”, D-LLD-60260-10001, 2013-Jan-16

[R-13] “SCR D-2004-00642 Trolley Drive Abnormal Stop”, D-2004-00642, 2004-Jan-21

[R-14] “Darlington NGS – Fuelling Machine Power Track Risk Assessment”, P0440/RP-005, 2004-Nov-05

[R-15] “DNGS Fuel Handling Power Track Improvement Project 16-31438 Project Execution Plan”, NK38-PEP-63578-0278117, 2010-Feb-15

Appendix A: Terms or Reference

Terms of Reference for Comprehensive Post-Implementation Review on Project 16-31438: Fuel Handling Power Track Improvement

A.1.0 BACKGROUND

On January 21st, 2004 at about 16:00 hours, the Darlington Fuel Handling Power Track (FHPT) system experienced a functional failure (SCR D-2004-00642). Intermediate roller #11 suffered a mechanical failure and had fallen into the lower cable pan becoming foreign material. The PT guide roller drum ran over the failed intermediate roller and broke free of its mounting. The guide roller drum shaft projected to the south of the main roller drum and began to interfere with supporting steelwork, halting motion of the FHPT system.

The failure caused significant damage to the Trolley (1,2 Power Track system, resulting in a 21 day outage of Unit 2 and a de-rating of Unit 1 to 59% for 15 days. The cost of the failure was $45M.

The root cause investigation on SCR D-2004-00642 was completed on March 16th, 2004. Assignments 9 and 10 called for an extensive failure analysis and risk assessment to identify initiatives that would reduce the high risk of failure of the FHPT system.

Risk assessment P0440/RP/005 (November 5th, 2004) identified the need for an improved surveillance system on the FHPT system as a means of reducing the operational risk, and for ensuring an effective maintenance program.

In April 2006 Project Charter D-PCH-63578-10004 was approved for capital project 16-31438, with the following objectives (critical success factors):

1. Design and installation of a Dynamic Instrumentation System (DI)
2. Design and installation of a Surveillance System (VSS)
3. Design and installation of a Failure Detection System (DRD)

On May 28th, 2007 the initial development Business Case Summary (D-BCS-63578-10008) for preliminary engineering was approved for $1.38 M. On November 13th, 2007 a partial BCS (D-BCS-63578-10009) was approved for $4.4M to commence design activities. On January 26th, 2009 a full release BCS (D-BCS-63578-10010) for phase 1 was approved for a further $8.53 M.

In December of 2009, a project write-off for $3.35 M was approved, dropping DI and DRD from the scope of project 16-31438. This was a result of a third party assessment leading to a joint review by Fuel Handling and Design Projects. It was determined that there was low value for money in proceeding with DI and DRD.

On July 29th, 2010 the full release BCS D-BCS-63578-10006 was approved for an additional $1.83 M for the completion of the Surveillance System for a final total of $16.16 M. The BCS states that a Comprehensive Post Implementation Review is required.

A.2.0 PURPOSE

OPG-PROC-0056 requires that a Comprehensive Post Implementation Review (CPIR) be completed if the project sponsor requires it. The full release BCS for project 16-31438 (D-BCS-63578-10006) states that a CPIR is required under section 7. The BCS provided a target CPIR approval date of November 31st, 2012. In a memorandum dated November 1st, 2012, the Chief Financial Officer approved a new CPIR approval date of March 30th, 2013.

The purpose of a CPIR is as follows:

- Verify the achievement of planned benefits identified in the business case and capture any other quantitative and qualitative outcomes of the investment.
- Assess the effectiveness of the project's intent, project charter, project execution plan, project execution, and operational performance results in meeting the business needs and the investment objectives stated in the BCS of the project.
- Review the appropriateness of risk management from business case approval through project completion and document lessons learned in different aspects of risk management including identification, analysis, mitigation plan, and monitoring and control throughout the life of the project.
- Review the effectiveness or quality of the BCS of the project looking back from results to provide feedback for future decisions. The financial evaluation used in the BCS should be re-assessed using actual results and documented in completed PIRs.

A.3.0 SCOPE

The DNGS Fuel Handling CPIR team will examine available project documents and records, and conduct interviews with key project participants and stakeholders, in order to:

- Evaluate the extent to which the promised results and the benefits stated in the approved business case were achieved, considering any assumptions or circumstances which may have changed since the original project approval;
- Review the project management methods and practices that were implemented throughout all project phases, in order to evaluate their effectiveness and impact on project outcomes; and
- Identify key lessons learned that can be captured and used to improve investment and project management practices within OPG. Where possible, the team will make

recommendations as to how these lessons learned can be implemented to provide sustained improvements.

A.4.0 DELIVERABLES

The primary deliverable will be a Comprehensive PIR report on Project 16-31438 including the following:

- An Executive Summary, Conclusions and Recommendations.
- A Background section with a review of the project history and rationale.
- An Assessment section which:
  - Reviews project results and other measures specified in the Comprehensive PIR Plan and re-evaluates measures specified in the BCS such as NPV (Net Present Value) against actual results.
  - Examines the project execution plan, scope management, program and resource management, execution, risk management, and the handling of health and safety issues.
  - Documents lessons learned in all aspects (doing the right things, doing them the right way, doing them well and getting the benefits) of the investment.
  - Reviews overall customer satisfaction with the project as well as overall product quality and realized benefits to date.

In addition, a summary of major findings and recommendations will be prepared for presentation on request to Nuclear or Corporate audiences. Records, notes and other working papers will be filed with the DNGS project records upon completion of the review.

A.5.0 SPONSOR

The CPIR sponsor is Steve Ramjist, Director of Operations & Maintenance at Darlington.

A.6.0 REVIEW TEAM

Name	Title	Department
Bill Barron	Senior Technical Engineer	DN Performance Engineering
Justin Julian	Senior Technical Engineer	DN Performance Engineering
Mukesh Mishra	Senior Technical Engineer	DN Design Projects
Silvester Wong	Senior Planning Engineer/Financial Analyst	Asset Planning & Integration
Violeta Garcia-Lee	Senior Planning Engineer/Financial Analyst	Asset Planning & Integration

A.7.0 REFERENCE DOCUMENTS

The CPIR report will base its conclusions and recommendations on the following documents:

Document	Document Number	Date
Project Charter	D-PCH-63578-10004	04-Apr-2006
BCS – Developmental Release	D-BCS-63578-10008	28-May-2007
BCS – Partial Release	D-BCS-63578-10009	13-Nov-2007
BCS – Full Release (Phase I)	D-BCS-63578-10010	26-Jan-2009
BCS – Full Release	D-BCS-63578-10006	29-Jul-2010
Scope Cancelation Memo	NK38-CORR-63578-0313360	26-Nov-2009
Project Execution Plan	NK38-PEP-63578-0278117	15-Feb-2010
Project Closure Report	FIN-FORM-PA-005	14-Nov-2012
PCRAF (8 in total)	N-FORM-10607	
REIS (3 in total)	FIN-FORM-PA-004	
EC List	See Master EC 96905	15-May-2012
AFS	See Master EC 96905	01-Nov-2011
BCS – Project 16-38472 (OM&A)	D-BCS-63578-10011	05-May-2010
Project Closure Report 16-38472	FIN-FORM-PA-005	11-Oct-2012

Additional documents may be added to this list as the CPIR document review and interview process takes place.

A.8.0 WORK PLAN

The team will target to complete its research and interviews and prepare a report for submission by March 30th, 2013.

	Description	Accountability/ Lead	Target Completion Date
1.	Prepare draft Terms of Reference (TOR), scope of work and schedule, identify team	Sponsor /Delegate	31-Dec-2012
2.	CPIR Workshop	Investment Planning	08-Jan-2013
3.	Review and confirm TOR with Team Members / 1st Team familiarization meeting; Finalize TOR	Team Leader	14-Jan-2013
4.	Project Documentation Review	Team	25-Jan-2013
5.	Conduct Interview Sessions with Stakeholders	Team	8-Feb-2013
6.	Analysis and Draft Report Compilation	Team	01-Mar-2013
7.	Draft report - Review with Key Stakeholders	Team	15-Mar-2013
8.	Finalize and Submit Final Report to Project Approval Authority	Team Leader	30-Mar-2013

A.9.0 SIGNATURES

Prepared By:		14-JAN-2013
	Bill Barron – CPIR Team Leader	Date
Reviewed by:		14 Jan 2013
	Fred Mason – Section Manager Darlington Fuel Handling Engineering	Date
Approved by:		Jan 14, 2013
	Steve Ramjist – Project Sponsor Director - Operations & Maintenance Darlington	Date

Appendix B: AFS Outstanding Action Tracking Items

AR #		Title
28134884	1	AFS - LAUNCH EQUIP MINOR REVS, DEC 98730, 98519 & 98518
28134884	2	AFS - RELEASE OF E-FILES FOR CD UPDATE, DEC 98730, 98519
28134884	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134884	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC 98730, 98519 & 98518
28134884	5	AFS - DRAWING UPDATE EC# 98730 (CIVIL)
28134884	6	AFS - DRAWING UPDATE EC# 98519 AND 98518 (ELECTRICAL)
28134884	7	AFS - NON-DRAWING UPDATE, DEC 98730, 98519 & 98518
28134884	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 98730 (CIVIL)
28134884	9	AFS - APPROVE DRAWINGS FOR ISSUE EC# 98519 & 98518 (ELEC)
28134884	10	AFS - APPROVE NON-DRAWINGS, EC 98730, 98519 & 98518
28134884	11	AFS - CONTROLLED DOCUMENTS ISSUE, EC 98730, 98519 & 98518
28134884	12	AFS - DESIGN EC CLOSE-OUT FOR EC 98730, 98519 & 98518
28134885	1	AFS - LAUNCH EQUIPMENT MINOR REV, DEC 98520 & 98521
28134885	2	AFS - RELEASE OF E-FILES FOR CD UPDATE, DEC 98520 & 98521
28134885	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134885	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC 98520 & 98521
28134885	5	AFS - DRAWING UPDATE EC# 98521 (CIVIL)
28134885	6	AFS - DRAWING UPDATE EC# 98520 (ELECTRICAL)
28134885	7	AFS - NON-DRAWING UPDATE, DEC 98520 & 98521
28134885	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 98521 (CIVIL)
28134885	9	AFS - APPROVE DRAWINGS FOR ISSUE, EC# 98520 (ELECTRICAL)
28134885	10	AFS - APPROVE NON-DRAWINGS, EC 98520 & 98521
28134885	11	AFS - CONTROLLED DOCUMENTS ISSUE, EC 98520 & 98521
28134885	12	AFS - DESIGN EC CLOSE-OUT FOR EC 98520 & 98521
28134886	1	AFS - LAUNCH EQUIPMENT MINOR REV DEC 101353 AND 101352
28134886	2	AFS - RELEASE OF E-FILES FOR CD, DEC 101353 AND 101352
28134886	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134886	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC# 101353 AND 101352
28134886	5	AFS - DRAWING UPDATE EC# 101352 (CIVIL)
28134886	6	AFS - DRAWING UPDATE EC# 101353 (ELECTRICAL)
28134886	7	AFS - NON-DRAWING UPDATE, DESIGN EC 101353 AND 101352
28134886	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 101352 (CIVIL)
28134886	9	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 101353 (ELEC)
28134886	10	AFS - APPROVE NON-DRAWINGS, EC # 101353 AND 101352

28134886	11	AFS - CONTROLLED DOCUMENTS ISSUE, EC # 101353 AND 101352
28134886	12	AFS - DESIGN EC CLOSE-OUT FOR EC # 101353 AND 101352
28134887	1	AFS - LAUNCH EQUIPMENT MINOR REV, DEC 103383 & 103382
28134887	2	AFS - RELEASE OF E-FILES FOR CD UPDATE, DEC 103383 & 103382
28134887	3	AFS - SUBMIT TECHNICAL PROCEDURE AR (TPARS) FOR UPDATE
28134887	4	AFS - NON-DRWG MARK-UP SUBMISSION, EC# 103383 & 103382
28134887	5	AFS - DRAWING UPDATE EC# 103383 (CIVIL)
28134887	6	AFS - DRAWING UPDATE EC# 103382 (ELECTRICAL)
28134887	7	AFS - NON-DRAWING UPDATE, DESIGN EC 103383 & 103382
28134887	8	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 103383 (CIVIL)
28134887	9	AFS - APPROVE DRAWINGS FOR ISSUANCE, EC# 103382 (ELEC)
28134887	10	AFS - APPROVE NON-DRAWINGS, EC # 103383 & 103382
28134887	11	AFS - CONTROLLED DOCUMENTS ISSUANCE, EC # 103383 & 103382
28134887	12	AFS - DESIGN EC CLOSE-OUT FOR EC # 103383 & 103382
28134887	13	AFS - CLOSE MASTER EC CLOSEOUT FOR EC 96905
28134888	1	REPLACEMENT OF VC25, 26 AND 29
28134888	2	TROLLEY 1/2 H/E CAMERA CABLE CONNECTOR REPLACE VIA SPLICE
28134888	3	INSTALLATION OF NEW CONDUIT SUPPORT BRACKET IN CSA DUCT
28134888	4	OPERATION FLOWSHEETS REVISED AND ISSUED IN PASSPORT
28134888	5	ENSURE PROCURE OF FFAAS RECEPTION BAY CAMERA CLEANING TOOL
28134888	6	REMOVE SCAFFOLDS FROM WFFAA DUCT NORTH SIDE
28134888	7	REMOVE SCAFFOLDS FROM EFFAA DUCT NORTH SIDE
28134888	8	REMOVE SCAFFOLDS FROM EFFAA DUCT SOUTH SIDE
28134888	9	REMOVE SCAFFOLDS FROM CSA DUCT SOUTH SIDE
28134888	10	TROUBLE SHOOT AND ALIGN CONNECTIONS IN MCR FOR VC27

EP Interrogatory #1

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

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 3, page 11

Has OPG submitted or received any documents from the Ministry of Energy in regards to the upcoming Long-term Energy Plan? If so, please provide them.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on the upcoming Long-term Energy Plan that is not relevant to deciding any issue on the approved Issues List in this application.

SEC Interrogatory #1

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

Interrogatory

Reference:
The application proposes substantial increases in the prices to be charged for OPG generation in the next decade and beyond, particularly from the nuclear facilities. Please provide a detailed analysis of the OPG's strategy to deal with potential demand destruction as the cost of OPG generation from its nuclear facilities, increases. Please provide all forecasts, estimates, or other future-looking documents that consider:

a. The price levels at which OPG generation becomes uncompetitive,

b. The price levels at which customers start to exit the grid to avoid OPG generation costs,

c. The numbers of customers, kwh volumes, and capacity requirements that will cease to rely on OPG generation at various price levels, or

d. The options available to the OPG to avoid demand destruction and its recursive price impacts.

Response

OPG has not analyzed whether demand may be reduced as a result of changes in the company's nuclear payment amounts, nor is it aware of any analyses indicating such reductions are likely. OPG has not developed a strategy to address this hypothetical issue, and does not have any documents that are responsive to the requests in this question.

OPG's Nuclear payment amounts are only one of several factors that affect the price of electricity in Ontario. It would be inaccurate to equate "OPG generation" with the price of electricity in the IESO-controlled market. In fact, OPG notes that its generation actually helps to moderate the overall commodity price.

SEC Interrogatory #2

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

Interrogatory

Reference:

Please provide summaries of all internal audit reports conducted since 2014, their findings, recommendations, and the status of any actions that are to be taken.

Response

OPG declines to answer on the basis that this is not an appropriate question. The question ignores the principle of proportionality which underlies the interrogatory process, in that it is overly broad and all encompassing.

The question asks OPG to review all audits for a three-year period and summarize the findings, recommendations and status. OPG's business generates a large quantity of documents that may be captured by the question asked in this interrogatory.

Without waiving this objection, Attachment 1 to this response provides a listing of all audits undertaken in the last three years except those related exclusively to OPG's unregulated business. If the information requested was refined to reference specific materials relating to an issue on the approved issues list, OPG could undertake to produce the relevant materials. For example, OPG has provided responsive material on audits of the Darlington Refurbishment Program in Ex. L-4.3-1 Staff-72 (b).

INTERNAL AUDIT
COMPLETED ENGAGEMENTS – 2014 to Q3 2016
(Note: Engagements pertaining exclusively to OPG's non-regulated business are excluded)

Board Report	Internal Audit Engagement
AFC 2014 Q1	R&FR – Contractor Requirements Audit
AFC 2014 Q1	Recruit, Select and Hire
AFC 2014 Q1	Parts and Equipment Obsolescence
AFC 2014 Q1	BT Change Initiatives – Progress Review of Process Risks and Controls Impacts
AFC 2014 Q2	DN Refurbishment - R&FR, Applications for Payment
AFC 2014 Q2	AG Management Actions Follow-Up Activity
AFC 2014 Q2	Environmental Management – Centre-led Oversight
AFC 2014 Q2	Administration of Contractual Documentation - HTO
AFC 2014 Q2	Hydro Asset Management
AFC 2014 Q2	Real Estate Process
AFC 2014 Q2	Project Governance Alignment with Project Development Protocol
AFC 2014 Q3	Network Security, Threat and Vulnerability Management
AFC 2014 Q3	New Horizons IT Support Agreement
AFC 2014 Q3	Administration of Contractual Documentation – Refurb.
AFC 2014 Q3	Finance Controls for Darlington Refurbishment Project
AFC 2014 Q4	New Horizons IT Support Agreement
AFC 2014 Q4	Rate Regulation Process
AFC 2014 Q4	Finance Controls for Darlington Refurbishment Project
AFC 2014 Q4	Critical Materials Procurement
AFC 2014 Q4	Nuclear Liability Cost Estimate
AFC 2014 Q4	Enterprise Systems Consolidation Project (ESCP) Implementation review
AFC 2014 Q4	Darlington Ops Readiness for Refurbishment
AFC 2014 Q4	Stakeholder Relations Program (SRP) Review - 2014
AFC 2014 Q4	Board Chair Expense Audit
AFC 2014 Q4	Directors of the Board Expense Audit
AFC 2014 Q4	ELT Expense Audit
AFC 2015 Q1	Investment Planning
AFC 2015 Q1	IT Service Agreement Costs Recovery
AFC 2015 Q2	Darlington Primary Heat Transport ("PHT") Pump Motor
AFC 2015 Q2	Darlington Outage Management
AFC 2015 Q2	Corporate Strategy & Planning Process
AFC 2015 Q2	Aboriginal Relations
AFC 2015 Q2	Employee Business Expense Audit

Board Report	Internal Audit Engagement
AFC 2015 Q2	Invoice Review Process – DRP Projects
AFC 2015 Q2	Controllership Function
AFC 2015 Q2	DRP Fraud Risk Assessment
AFC 2015 Q3	Pickering Planned Outage Management Audit
AFC 2015 Q3	Nuclear Warehousing and Logistics Audit
AFC 2015 Q3	Real Time Process Controls Systems ("RTPCS") Security Audit - Nuclear
AFC 2015 Q3	Emergency Management Audit
AFC 2015 Q3	Enterprise System Consolidation Project ("ESCP") - Post Implementation Review
AFC 2015 Q3	Finance and Accounting Transactions – Shared Services Audit
AFC 2015 Q3	Integrated Revenue Planning Audit
AFC 2015 Q3	Security Processes Audit
AFC 2015 Q3	Strategic Sourcing Audit
AFC 2015 Q3	Hydro Production – Water Management Audit
AFC 2015 Q3	New Horizons Systems Solutions ("NHSS") – Billings Audit
AFC 2015 Q3	Pension and OPEB Audit
AFC 2015 Q3	Nuclear Contractor Time Reporting (Update - Design Phase)
AFC 2015 Q4	Isotope Sales – Mb-Microtec
AFC 2015 Q4	Nuclear Generation Planning & Production
AFC 2015 Q4	Nuclear Engineering Strategy
AFC 2015 Q4	Isotopes Sales - SRBT
AFC 2015 Q4	HR Recruiting - Follow-up to AG Findings
AFC 2015 Q4	Code of Business Conduct
AFC 2015 Q4	EPC Contractors Procurement Oversight
AFC 2015 Q4	Nuclear Liability Cost Estimate
AFC 2015 Q4	Isotope Sales - UKAEA
ARC 2016 Q1	Project Controls - Projects & Modifications ("P&M") Group
ARC 2016 Q1	Darlington Nuclear Refurbishment ("DNR") Contractor Invoicing
ARC 2016 Q1	DNR Onboarding
ARC 2016 Q1	DNR Project Management
ARC 2016 Q1	ES MSA Recovery Negotiations - Follow-up on 2013 Auditor General Findings
ARC 2016 Q1	Services Procurement
ARC 2016 Q1	Board of Directors On-Boarding
ARC 2016 Q1	Compensation - Follow-up on 2013 Auditor General Findings
ARC 2016 Q1	2015 Business Expense Audit – Board of Directors
ARC 2016 Q1	2015 Business Expense Audit – Chairman of Board
ARC 2016 Q1	2015 Business Expense Audit – Executive Leadership Team
ARC 2016 Q1	Ontario Energy Board ("OEB") Rate Application

Board Report	Internal Audit Engagement
ARC 2016 Q1	Stakeholder Return Program
ARC 2016 Q2	SMART Objectives
ARC 2016 Q2	IT Governance & Risk Management
ARC 2016 Q2	Law Contract Management Support
ARC 2016 Q2	Business Transformation Performance
ARC 2016 Q2	Business Continuity
ARC 2016 Q2	Darlington Nuclear Refurbishment (“DNR”) Contractor Management
ARC 2016 Q2	DNR Retube & Feeder Replacement (“R&FR”) Project - Construction & Tooling
ARC 2016 Q2	IESO Settlements
ARC 2016 Q2	DNR Integrated Database (“IDB”) for Project Reporting
ARC 2016 Q2	DNR Turbine Generator Project - Engineering
ARC 2016 Q3	Cyber Security - IT End Point Security
ARC 2016 Q3	Data Loss Prevention
ARC 2016 Q3	Project Management – Inspection & Maintenance Services (“IMS”) Initiatives
ARC 2016 Q3	SMART Objectives – Follow up
ARC 2016 Q3	Learning and Development
ARC 2016 Q3	Supplier Quality
ARC 2016 Q3	DNR Contractor Procurement - Retube & Feeder Replacement (“R&FR”) Project

SEC Interrogatory #4

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

Interrogatory

Reference:

Please provide a copy of all shareholder directives that may impact the OPG's regulated business. Please provide details of any changes to any shareholder directives that were in place at the time of OPG's last payment amounts application (EB-2013-0321).

Response

The Nuclear Directive (June 16, 2006) impacts OPG's regulated business. It has not changed since the time of OPG's EB-2013-0321 payment amounts application, and can be found on OPG's website at
http://www.opg.com/about/management/open-and-accountable/Documents/directive_nuclear.pdf

There are also several directives posted on the OPG website that relate to aspects of the Bruce lease agreement and related agreements. However, for the reasons set out in EB-2012-0002 L-1-7 SEC-3 (which includes references to relevant portions of the OEB's Decision with Reasons in EB-2007-0905 relating to the Bruce Lease), and as referenced in L-7.2-1 Staff-203, those directives are not relevant to this proceeding. In the EB-2007-0905 Decision at p.99, the OEB held, amongst other things, that "[t]he Board, however, has no authority to set or review the terms of the lease between OPG and Bruce Power."

SJ Interrogatory #1

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

Interrogatory

Reference:

OPG has assembled a plan that assumes that most of the elements will inevitably be approved in the future even though most of those elements have not in fact been approved, and there is a great deal of evidence to suggest that they should not be approved. Their submission as it stands fails to deal with the most fundamental questions:

Is there a need in Ontario for refurbishment of the nuclear stations?

Response

OPG can only respond regarding the Darlington Refurbishment Program. The Ministry of Energy, which is ultimately responsible for energy planning in Ontario, has endorsed the DRP. Moreover, the Province has removed the question of the need for DRP from this hearing by amending to O. Reg. 53/05 to add section 12 (v), which reads: "the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment."

SJ Interrogatory #2

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

Interrogatory

Reference:

OPG has assembled a plan that assumes that most of the elements will inevitably be approved in the future even though most of those elements have not in fact been approved, and there is a great deal of evidence to suggest that they should not be approved. Their submission as it stands fails to deal with the most fundamental questions:

Is the nuclear option economically viable?

Response

Please see Ex. L-1.2-18 SJ-1.

SJ Interrogatory #3

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

Interrogatory

Reference:

OPG has assembled a plan that assumes that most of the elements will inevitably be approved in the future even though most of those elements have not in fact been approved, and there is a great deal of evidence to suggest that they should not be approved. Their submission as it stands fails to deal with the most fundamental questions:

Is the nuclear option compatible with the commitments to achieve environmental sustainability?

Response

Yes. Over the period covered by this application, OPG's nuclear generating facilities are forecast to produce about 188 TWh of baseload energy that is virtually free of greenhouse gases or smog.

SJ Interrogatory #4

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

Interrogatory

Reference:

OPG has assembled a plan that assumes that most of the elements will inevitably be approved in the future even though most of those elements have not in fact been approved, and there is a great deal of evidence to suggest that they should not be approved. Their submission as it stands fails to deal with the most fundamental questions:

All of the OPG nuclear stations are very old and will soon need to be replaced by new stations, at a cost that is so high that it could bankrupt the province.

Response

OPG disagrees with this statement. The application presents the work and associated funding required to refurbish the Darlington station and to extend the operation of Pickering. Both these projects have been endorsed by the Province. The application does not seek funding to construct replacement stations.

SJ Interrogatory #5

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

Interrogatory

Reference:

OPG has assembled a plan that assumes that most of the elements will inevitably be approved in the future even though most of those elements have not in fact been approved, and there is a great deal of evidence to suggest that they should not be approved. Their submission as it stands fails to deal with the most fundamental questions:

The plan that has been proposed by OPG would obstruct Ontario's ability to implement alternatives that would be more economically and environmentally viable.

Response

OPG disagrees with this statement. Both the Darlington Refurbishment Program and the extended operation of Pickering have been endorsed by the Ministry of Energy following consideration of alternatives.

Board Staff Interrogatory #5

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

Interrogatory

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

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

Response

Scenario 1: OPG's proposed 11% rate smoothing proposal

OPG's proposal results in an average residential month customer bill increase of $1.05. The annualized residential customer impact based on OPG's smoothing proposal is provided in Ex. I1-1-2 Table 1, line 4. The table also provides the methodology for the calculation. The average of the annualized residential customer impact is provided in Chart 1 below:

Chart 1: Derivation of $1.05 Average Customer Bill Impact

	2017	2018	2019	2020	2021	Average
Typical Bill Impact ($/Month)	(1.29)	1.73	1.07	1.86	1.89	**1.05**

Scenario 2: Constant Rates without Deferral beyond the 2017-2021 IR Term

As noted at the reference (Ex. A1-3-3, p. 2), if OPG were to defer no revenue requirement beyond the IR term, the nuclear base rate increase would be approximately 15% per year. A constant 15% per year rate increase that recovers the entire proposed nuclear revenue requirement over the 2017-2021 period results in an average residential monthly customer bill increase of approximately $1.85 (Ex. A1-3-3, p. 2, lines 10-13).

The calculations to derive this bill impact are provided in Attachment 1, Tables 1-3. The calculations are summarized below:

- The 15% annual rate increase is reflected in Attachment 1, Table 3, line 10.

- The total nuclear payment amount plus riders from Attachment 1, Table 3, line 13 is reflected in the Comparison of Percent Change in Illustrative Payments Amounts in Attachment 1, Table 2, line 2.
- The resulting production weighted average rate from Attachment 1, Table 2, line 8 is reflected in the Annualized Residential Customer Impact of Illustrative Rates in Attachment 1, Table 1, line 7.
- The resulting average residential customer bill impact is shown in Attachment 1, Table 1, line 4, column f.

Table 1
Annualized Residential Consumer Impact of Illustrative Rates
EB-2013-0321 / EB-2014-0370 to EB-2016-0152

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount	Average
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Typical Consumption[1] (kWh/Month)**	789	789	789	789	789	789
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	392	394	397	388	376	389
3	**Typical Bill[1] ($/Month)**	150.58	150.58	150.58	150.58	150.58	150.58
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**(0.77)**	**2.39**	**1.91**	**2.81**	**2.97**	**1.86**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**-0.5%**	**1.6%**	**1.3%**	**1.9%**	**2.0%**	**1.2%**
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	60.66	58.70	64.77	69.57	76.82	84.71
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	58.70	64.77	69.57	76.82	84.71	-
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	(1.96)	6.07	4.80	7.26	7.88	(84.71)
9	Total OPG Regulated Production[4] (TWh)	68.3	68.7	69.3	67.6	65.6	67.9
10	Forecast of 2017 Provincial Demand[5] (TWh)	137.6	137.6	137.6	137.6	137.6	137.6
11	OPG Proportion of Consumer Usage (line 9 / line 10)	49.7%	49.9%	50.3%	49.1%	47.7%	49.3%

Notes:
1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at:
http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
Typical Consumption includes line losses (Assumed loss factor of 1.0525)
2 From Ex L-1.3-1 Staff-005 Attachment 1 Table 2, line 8
3 Uses Illustrative nuclear payment amount and riders from Ex. L-1.3-1 Staff005 Attachment1 Table 3, IRM Hydro rate (illustrative after 2017) per Ex. I1-2-1 Table 1
4 From Ex. I1-1-2 Table 2, line 5.
5 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

Numbers may not add due to rounding.
Privileged and confidential. Prepared in contemplation of litigation.

Table 2
Computation of Percent Change in Illustrative Payment Amounts
EB-2013-0321 / EB-2014-0370 to EB-2016-0152

Line No.	Description	Note	2016 per EB-2013-0321 Payment Amounts Order plus EB-2014-0370 Riders	2017 per EB-2016-0152 Illustrative Payment Amount plus EB-2016-0152 Riders	2018 per EB-2016-0152 Illustrative Payment Amount plus EB-2016-0152 Riders	2019 per EB-2016-0152 Illustrative Payment Amount	2020 per EB-2016-0152 Illustrative Payment Amount	2021 per EB-2016-0152 Illustrative Payment Amount
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	44.55	43.15	43.77	42.97	43.61	44.27
2	**Nuclear Rate Including Rider ($/MWh)**	2	72.30	71.03	81.26	90.17	103.70	119.25
3	**Regulated Hydroelectric Production (TWh)**	3	33.8	30.2	30.2	30.2	30.2	30.2
4	**Forecast Nuclear Production (TWh)**	3	46.8	38.1	38.5	39.0	37.4	35.4
5	**Total Production (TWh)** (line 3 + line 4)		80.6	68.3	68.7	69.3	67.6	65.6
6	**Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 3 / line 5)		18.69	19.09	19.26	18.75	19.51	20.39
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		41.97	39.61	45.51	50.81	57.32	64.31
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		60.66	58.70	64.77	69.57	76.82	84.71
9	Percentage Change in Hydroelectric Rate Including Rider	4		-3.2%	1.4%	-1.8%	1.5%	1.5%
10	Percentage Change in Nuclear Rate Including Rider	4		-1.8%	14.4%	11.0%	15.0%	15.0%
11	Percentage Change in Overall Payment Amount			-3.2%	10.3%	7.4%	10.4%	10.3%

Notes:

1 Col. (a) is average Regulated Hydroelectric payment amount including riders for Jul-Dec 2015 (production-weighted average of previously and newly regulated hydroelectric base rates and riders in effect at the end of 2015). See Ex. I1-2-1 Table 1(a). Col. (b) - (f) is proposed EB-2016-0152 payment amount plus riders from Ex. I1-2-1 Table 1 line 10.

2 Col. (a) is base rate of $59.29/MWh (EB-2013-0321 Payment Amounts Order, Appendix D, Table 1, line 3) plus nuclear rider 2016 from EB-2014-0370 ($10.84/MWh) plus Nuclear Interim Period Shortfall Rider from EB-2014-0370 ($2.17/MWh).
Col. (b) - (f) are the illustrative rates associated with Illustrative Payment Amounts, plus riders, as referenced in Ex L-1.3-1 Staff-005, Attachment 1, Table 1, line 13

3 Regulated Hydroelectric 2017-2021 is 2015 actual production, 2016 Budget production used to calculate 2016 total production weighted average rate
Nuclear from EB-2016-0152 Ex. E2-1-2_Table 1

4 Rider included per Ex. H1-2-1 Tables 1 and 2 only - no assumptions made for future riders in the 2019-2021 period

Table 3
Illustrative Rates for Unsmoothed Payment Amounts and Riders - Nuclear
Test Period January 1, 2017 to December 31, 2021

Line No.	Description	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)
	PAYMENT AMOUNT:					
1	**Revenue Requirement Before Stretch Factor [1] ($M)**	3,189.9	3,255.0	3,295.1	3,790.0	3,509.8
2	**Nuclear Base OM&A[2]**	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
3	**Nuclear Allocated Corporate Costs[3]**	448.9	437.2	442.7	445.0	454.1
4	**Total OM&A Applicable for Stretch Factor[4]**	1,659.5	1,663.2	1,691.1	1,709.7	1,730.4
5	**Nuclear Stretch Factor (Ex. A1-3-2, Chart 9)**		0.3%	0.3%	0.3%	0.3%
6	**Cummulative Nuclear Stretch Dollars** ((line 4 x line 5) + Prior Year)	0.0	5.0	10.1	15.2	20.4
7	**Revenue Requirement Net of Stretch Factor ($M)** (line 1 - line 6)	3,189.9	3,250.0	3,285.0	3,774.8	3,489.4
8	**Forecast Production[5] (TWh)**	38.1	38.5	39.0	37.4	35.4
9	**Illustrative Unsmoothed Payment Amount ($/MWh)** (line 7 / line 8)	83.73	84.48	84.17	101.05	98.62
10	**Constant % Increase Without Deferral[6] (%)**	15.0%	15.0%	15.0%	15.0%	15.0%
11	**Illustrative Constant Rate Increse Without Deferral ($/MWh)**	68.18	78.41	90.17	103.70	119.25
	DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:					
12	**Payment Rider[7] ($/MWh)**	2.85	2.85			
13	**Total of Nuclear Payment Amount Plus Riders ($/MWh)** (line 11 + line 12)	71.03	81.26	90.17	103.70	119.25

Notes:
1 From Ex. I1-1-1 Table 2, line 24.
2 Ex. F2-1-1 Table 1
3 Ex. F2-1-1 Table 1
4 Please see section 3.2 of Ex. A1-3-2
5 From Ex. E2-1-1 Table 1, line 3, cols. (e) through (i).
6 2017 calculated as $59.29/MWh from EB-2013-0321 Payment Amounts Order, Appendix D, Table 1, line 3, escalated by 15%.
7 From Ex. H1-2-1 Table 2, line 18, col (g)

AMPCO Interrogatory #11

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

Interrogatory

Reference:
Ref: A1-2-2 Page 1

a) Please provide OPG's Budgeted, Board Approved and Actual Nuclear Revenue Requirement for the years 2010 to 2015 and forecast for 2016.

Response

Table 1 in Attachment 1 provides OPG's Budgeted, Board Approved and "Actual" Nuclear Revenue Requirement for the years 2010 to 2015 and forecast for 2016. OPG's Budgeted revenue requirement is equal to the requested revenue requirement. There is no Budgeted or Board Approved Nuclear Revenue Requirement for 2010 and 2013.

Numbers may not add due to rounding.

Table 1

OPG Nuclear Revenue Requirement

	2010	2011	2012	2013	2014	2015	2016
Requested Revenue Requirement ($M)[1]	N/A	2,671.1	2,788.3	N/A	3,228.5	3,166.9	N/A

	2010	2011	2012	2013	2014	2015	2016
OEB Approved Revenue Requirement ($M)[1]	N/A	2,586.0	2,665.5	N/A	2,790.4	2,877.6	N/A

	2010	2011	2012	2013	2014	2015	2016
OEB "Actual" Revenue Requirement ($M)[2, 3]	2,429.8	2,590.0	2,917.1	2,677.5	2,763.1	2,883.7	2,927.5

Notes

1: 2011 and 2012 from EB-2010-0008, Payment Amounts Order, Appendix A, Table 2
2014-2015 from EB-2013-0321, Payment Amounts Order, Appendix A, Table 3

2: 2011-2012 from EB-2013-0321, Ex. N2-1-1 Table 3
2014-2016 from EB-2016-0152, Ex. I1-1-1 Table 2

3: The 2014 and 2015 actual revenue requirements have been corrected for errors identified by OPG in Ex. I1-1-1 Table 2.

AMPCO Interrogatory #12

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

Interrogatory

Reference:
Ref: I1-1-2 Page 1

Preamble: OPG provides the estimated monthly consumer bill impacts associated with the revenue requirement and OPG's deferral and variance account proposals.

a) Please provide the annualized bill impacts ($ and %) for a typical GS>50 kW and Large Use customer for the years 2017 to 2021 and show the calculations.

Response

See Ex. L-01.3-5 CCC-9. OPG is able to provide the annualized residential consumer impacts as presented in Ex. I1-1-2 table 1, by largely relying on the OEB's Bill Calculator which provides a sample bill calculation for each distributor within the province of Ontario using Time of Use rates. A similar tool is not available for GS > 50 kW and Large Use customers, and as such OPG is unable to provide bill impacts for rate classes other than the residential class.

CCC Interrogatory #9

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

Interrogatory

Reference:
Reference: Ex. I1/T1/S2 Table 1

This table illustrates how the average residential consumer will experience the rate changes proposed by OPG. The Council is interested in understanding how much average residential consumers have been charged (including how much of their energy had been supplied) by OPG since OPG became subject to rate regulation, and how those rates have compared to the total cost per kWh charged to the average residential consumer under the Regulated Price Plan (the "RPP") (understanding that the RPP is a blend of OPG charges and charges from other providers).

a) Please provide a version of this table that:

i) extends back to and includes the year 2007;

ii) adds a line that shows the per kWh charge that a typical residential customer paid/will pay OPG in each year (i.e. for the years on the existing table that charge, we believe, is line 8/1000); and

iii) adds a line that shows the per kWh charge that a typical residential customer paid/will pay for all their electricity (for the purposes of the table the Council expects it is sufficient to assume that the typical residential customer throughout the period is an RPP customer).

Response

OPG does not have the information necessary to produce the table as requested by CCC.

OPG is able to provide the annualized residential consumer impacts as presented in Ex. I1-1-2 table 1, by largely relying on the OEB's Bill Calculator which provides a sample bill calculation for each distributor within the province of Ontario using Time of Use rates. There is a large amount of underlying data behind the OEB's Bill Calculator, including distributor specific distribution charges, default time of use consumption, Global Adjustment prices, and so on. In addition, this Bill Calculator is available only as presented on the OEB's website and updated as necessary by the OEB. OPG does not have access to a version of this bill calculator with underlying assumptions back to 2007.

OPG has provided, as Attachment 1, a copy of all consumer impacts provided in the Payment Amounts Order[1] from OPG rate cases as follows:

- EB-2007-0905, Payment Amounts Order, Appendix A, Table 6
- EB-2010-0008, Payment Amounts Order, Appendix A, Table 8
- EB-2012-0002, Payment Amounts Order, Appendix A, Table 6
- EB-2013-0321, Payment Amounts Order, Appendix A, Table 9
- EB-2014-0370, Payment Amounts Order, Appendix A, Table 4
- EB-2016-0152, Exhibit I1-1-2, Table 1

[1] EB-2016-0152 impacts are as proposed in Ex. I1-1-2 Table 1

Numbers may not add due to rounding.

EB-2007-0905
Appendix A
Table 6

Table 6
Typical Residential Customer Bill Impact
Board Approved Revenue Requirement Adjustments ($M)
Test Period April 1, 2008 to December 31, 2009

Line No.	Description	Test Period: Regulated Hydroelectric	Test Period: Nuclear	Test Period: Total
		(a)	(b)	(c)
1	**Typical Residential Consumer Usage (KWh/Month)**[1]	1,000.0	1,000.0	1,000.0
2	**Gross-up for Line Losses**[2]	1.0522	1.0522	1.0522
3	**OPG Portion**[3]	11.4%	31.9%	43.3%
4	**Residential Consumer Usage of OPG Generation (KWh/Month)**	119.8	336.0	455.8
	(line 1 * line 2 * line 3)			
	IMPACT OF RECOVERY OF APPROVED REVENUE REQUIREMENT:			
5	**Approved Revenue Deficiency After Mitigation**[4]	115.2	483.0	598.3
6	**Approved Production Forecast (TWh)**[5]	31.5	88.2	119.7
7	**Required Recovery ($/MWh)**	3.70	5.50	5.00
	(line 5 / line 6)			
8	**Typical Monthly Consumer Bill Impact ($)**	0.44	1.85	2.28
	(line 4 * line 7)			
9	**Typical Monthly Residential Consumer Bill ($)**[6]	111.63	111.63	111.63
10	**Percentage Increase in Consumer Bills**	0.40%	1.66%	2.05%
	(line 8 / line 9)			

Notes:
1 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 1
2 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 2
3 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 3
4 From Payment Amounts Order App A Table 3, line 7
5 From Payment Amounts Order App A Table 3, line 1
6 From EB-2007-0905 Ex K1-T1-S3 Table 1, line 11

Numbers may not add due to rounding.

Payment Amounts Order
EB-2010-0008
Appendix A
Table 8

Table 8
Annualized Residential Consumer Impact Assessment
Board Approved Revenue Requirement
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Notes	Test Period Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Typical Residential Consumer Usage (kWh/Month)**	1	800.0	800.0	800.0
2	**Gross-up for Line Losses**	2	1.0728	1.0728	1.0728
3	**OPG Portion**	3	14.0%	35.9%	49.9%
4	**Residential Consumer Usage of OPG Generation (kWh/Month)**		119.9	308.2	428.2
	(line 1 x line 2 x line 3)				
	IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY (SUFFICIENCY):				
5	**Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)**	4	(32.5)	(133.5)	(166.0)
6	**Impact of Amortization of Variance and Deferral Account Amounts ($M)**	5	(60.2)	216.8	156.7
7	**Amount to be Recovered From Customers ($M)** (line 5 + line 6)		(92.6)	83.3	(9.3)
8	**Forecast Production (TWh)**	6	39.7	101.9	141.6
9	**Required Recovery ($/MWh)** (line 7 / line 8)		(2.34)	0.82	(0.07)
10	**Typical Monthly Consumer Bill Impact ($)**		(0.28)	0.25	(0.03)
	(line 4 x line 9)				
11	**Typical Monthly Residential Consumer Bill ($)**	7	109.40	109.40	109.40
12	**Percentage Change in Consumer Bills**		-0.26%	0.23%	-0.03%
	(line 10 / line 11)				

Notes:
1. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 1.
2. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 2.
3. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 3, adjusted for production forecast increases per OEB Decision.
4. From Payment Amounts Order, Appendix A, Table 3, line 6.
5. For regulated hydroelectric, amortization from Payment Amounts Order, Appendix A, Table 1, line 25.
   For nuclear, amortization of $403.2M from Payment Amounts Order, Appendix A, Table 2, line 25, less the EB-2007-0905 approved Rider A of $2.00/MWh multiplied by the forecast nuclear production for March 1, 2011 to December 31, 2012 of 93.2 TWh per Payment Amounts Order, Appendix E, Table 1, line 16.
6. From Payment Amounts Order, Appendix A, Table 3, line 1.
7. From EB-2010-0008 Ex. I1-T1-S2, Table 1, line 11.

Numbers may not add due to rounding.

Table 6 *
Annualized Residential Consumer Impact Assessment

Line No.	Description	Residential
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 12)	409
3	**Typical Bill[1] ($/Month)**	116.30
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 /1000)	**0.74**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**0.6%**
6	Current OPG weighted average Hydro & Nuclear Rate ($/MWh)	49.77
7	Proposed OPG weighted average Hydro & Nuclear Rate ($/MWh)	51.58
8	Change in OPG weighted average Hydro & Nuclear Rate ($/MWh) (line 7 - line 6)	1.81
9	Change in OPG weighted average Hydro & Nuclear Rate (%) (line 8 / line 6)	4%
10	Total Forecast 2013-14 Regulated Production[2] (TWh)	138.8
11	Forecast of Provincial Demand[3] (TWh)	285.6
12	OPG Proportion of Consumer Usage (line 10 / line 11)	48.6%

Notes:

* This table is replicated from Ex. M1-1, Attachment 4, Table 22.

1 For Residential consumers, average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills. Typical Consumption includes line losses.

2 See L-3-5 EP-02

3 Based on IESO June 2012 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014, OPG used the IESO Energy demand forecast for 2013 (142.8 TWh) and assumed the 2014 forecast to be equal to the 2013 forecast (142.8 TWh + 142.8 TWh = 285.6 TWh).

Numbers may not add due to rounding.

Table 9
Annualized Residential Consumer Impact
Board Approved Revenue Requirement
Test Period January 1, 2014 to December 31, 2015

Line No.	Description	Amount
		(a)
1	**Typical Consumption[1] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	461
3	**Typical Bill[2] ($/Month)**	118.69
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**2.53**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**2.1%**
6	Current OPG weighted average Rate[3] ($/MWh)	49.52
7	Payment Amounts Order OPG test period weighted average Rate[3] ($/MWh)	55.01
8	Change in OPG weighted average Rate ($/MWh) (line 7 - line 6)	5.49
9	Payment Amounts Order Forecast 2014-15 OPG Regulated Production[4] (TWh)	154.6
10	Forecast of Provincial Demand[5] (TWh)	282.4
11	OPG Proportion of Consumer Usage (line 9 / line 10)	54.8%

Notes:
1 From EB-2013-0321, Ex. I1-1-2, Table 1, line 1.
2 From EB-2013-0321, Ex. I1-1-2, Table 1, line 3.
3 From Payment Amounts Order, Appendix A, Table 9a, line 11.
4 From Payment Amounts Order, Appendix A, Table 9a, line 7.
5 From EB-2013-0321, Ex. I1-1-2, Table 1, line 10.

Table 4
Annualized Residential Consumer Impact[1]
January 1, 2015 to December 31, 2016

Line No.	Description	Amount
		(a)
1	**Typical Consumption[2] (kWh/Month)**	842
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	489
3	**Typical Bill[2] ($/Month)**	132.57
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**1.93**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**1.5%**
6	EB-2013-0321 Payment Amounts Order OPG weighted average rate for 2015 [3] ($/MWh)	54.75
7	Blended OPG 2015-16 weighted average rate with EB-2014-0370 approved payment riders [4] ($/MWh)	58.69
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	3.94
9	EB-2013-0321 Approved 2014-15 OPG Regulated Production [5] (TWh)	161.6
10	Forecast of Provincial Demand [6] (TWh)	278.3
11	OPG Proportion of Consumer Usage (line 9 / line 10)	58.1%

Notes:
1. All values are as shown in Ex. M1-1-1 Attachment 2 Table 3, page 3 of 6.
2. Typical monthly consumption (800 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
   Typical Consumption includes line losses.
3. From EB-2014-0370 Payment Amounts Order App. A, Table 5, line 11, col. (a).
4. From EB-2014-0370 Payment Amounts Order App. A, Table 5, line 11, col. (b).
5. From EB-2014-0370 Payment Amounts Order App. A, Table 5, line 7.
6. Based on forecast demand for 2014 (139.5 TWh) and 2015 (138.8 TWh) from Table 3.1 of IESO 18-Month Outlook Update for September 2014 to February 2016, published September 4, 2014.

Numbers may not add due to rounding.

Table 1
Annualized Residential Consumer Impact
EB-2013-0321 / EB-2014-0370 to EB-2016-0152

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount
		(a)	(b)	(c)	(d)	(e)
1	**Typical Consumption[1] (kWh/Month)**	789	789	789	789	789
2	**Typical Usage of OPG Generation (kWh/Month)** (line 1 x line 11)	392	394	397	388	376
3	**Typical Bill[1] ($/Month)**	150.58	150.58	150.58	150.58	150.58
4	**Typical Bill Impact ($/Month)** (line 2 x line 8 / 1000)	**(1.29)**	**1.73**	**1.07**	**1.86**	**1.89**
5	**Typical Bill Impact (%)** (line 4 / line 3)	**-0.9%**	**1.1%**	**0.7%**	**1.2%**	**1.3%**
6	Prior Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	60.66	57.37	61.76	64.45	69.26
7	Current Year weighted average rate with proposed payment amounts and riders[2,3] ($/MWh)	57.37	61.76	64.45	69.26	74.27
8	Change in OPG weighted average rate ($/MWh) (line 7 - line 6)	(3.29)	4.39	2.69	4.81	5.02
9	Total OPG Regulated Production[4] (TWh)	68.3	68.7	69.3	67.6	65.6
10	Forecast of 2017 Provincial Demand[5] (TWh)	137.6	137.6	137.6	137.6	137.6
11	OPG Proportion of Consumer Usage (line 9 / line 10)	49.7%	49.9%	50.3%	49.1%	47.7%

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at:
http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility
Typical Consumption includes line losses (Assumed loss factor of 1.0525)

2 From Ex. I1-1-2 Table 2, line 8

3 Uses Nuclear smoothed rate per Ex. I1-3-1 Table 1, IRM Hydro rate (illustrative after 2017) per Ex. I1-2-1 Table 1

4 From Ex. I1-1-2 Table 2, line 5.

5 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

CCC Interrogatory #10

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S3/p. 2

The evidence states, "If OPG were to propose a constant nuclear base rate increase that covered the entire proposed nuclear revenue requirement for the 2017-2021 period, that rate increase would be approximately 15 percent per year, and the customer bill impact would be over 1.2 percent annually or approximately $1.85 on a typical monthly residential bill each year."

a. Under this proposal, to recover the full revenue requirement over the 2017-2021 period, what would be the interest savings relative to OPG's rate smoothing proposal?

b. Did OPG undertake customer engagement to determine whether ratepayers would prefer to pay more up front in order to pay less overall (less interest over time)? If so please provide the results of that research.

Response

a) If the OEB were not to defer any nuclear revenue requirement beyond the 2017-2021 period, interest expense would be reduced by approximately $155M. The cumulative interest expense resulting from the proposed 11% rate smoothing is forecast to be $284M, as provided in the Nuclear Rate Smoothing Presentation, September 23, 2016, Slide 6. An annual payment amounts increase of approximately 15% would be required to recover the full revenue requirement as illustrated in the chart below. The cumulative illustrative interest expense is $129M as shown in line 6, column (e). The chart shows the annual deferred revenue requirement and the associated interest. L1.3-1 Staff-005, Attachment 1, Table 3 provides the associated rates.

Chart 1:
Illustration of the Annual Deferred Revenue Requirement and the Associated Interest

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount
		(a)	(b)	(c)	(d)	(e)
1	**Unsmoothed Rate[1] ($/MWh)**	83.73	84.48	84.17	101.05	98.62
2	**Illustrative Smoothed Rates, Based on a Constant Rate of Change[2] ($/MWh)**	68.05	78.11	89.65	102.89	118.10
3	**Forecast Production[3] (TWh)**	38.1	38.5	39.0	37.4	35.4
4	**Annual Deferred Amount ($M)**	597	245	(214)	(69)	(689)
5	**Interest Expense ($M)**	15	34	35	30	15
6	**Cumulative Interest ($M)**	15	48	84	114	129

Notes:
1 Ex. I1-3-1 Table 1, line 9
2 Reflects a rate of increase of approximately 15% to provide for recovery of the deferred revenue requirement and interest. The Rate Smoothing Deferral Account Balance is $0 in 2021
3 Ex. I1-3-1 Table 1, line 8

b) As described in Ex. A1-3-2, section 5, OPG's customer engagement activities did not specifically address this issue. However, five of the six considerations that informed OPG's rate smoothing proposal reflect the RRFE principle of Customer Focus. One of these considerations, Intergenerational Equity, specifically balances the customer bill impact of deferred recovery with the carrying costs that will ultimately be borne by customers in subsequent periods as a result of that deferral. (Ex. A1-3-3, p. 5, lines 29-31).

EP Interrogatory #2

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

Interrogatory

Reference:
Reference: Exhibit A1, Tab 3, Schedule 2, page 33

OPG states that it is "not proposing a nuclear industry productivity adjustment," as the "nature and scale of the capital work planned for the IR period mean that productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period."

Can OPG explain why a productivity factor couldn't be used for other work unrelated to the Darlington Refurbishment Project?

Response

The above statement applies generally and equally to Pickering and Darlington. Both facilities are undertaking programs intended to refurbish or extend operations. These programs involve incremental investments that will impact operations at both facilities, such that productivity trends associated with Nuclear operations during the 2017-2021 period will be substantially different from those in the historic period on which any total factor productivity analysis would be derived.

In this context – one in which operations at both facilities will be materially different from the past – a retrospective productivity factor would not be appropriate for setting rates for OPG.

EP Interrogatory #3

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

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 3

Please list any costs to OPG or its shareholder if it were to end the DRP after the refurbishment of the Unit 2.

Response

Please see L-4.3-8 GEC-9.

EP Interrogatory #23

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

Interrogatory

Reference:

Can OPG list the amount of SBG by quarter in 2013, 2014, 2015 and to date in 2016.

Response

There is no SBG spill allocable to OPG Nuclear during the period.

EP Interrogatory #24

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

Interrogatory

Reference:

Can OPG indicate for each of 2012, 2013, 2014, 2015 and 2016 (to date) how often (in hours/years or %) OPG received a higher rate for its nuclear generation than IESO's market price.

Response

Chart 1 shows the percent of each year in which OPG received a higher rate for its nuclear generation.

Chart 1
Percent of Year Nuclear Regulated Rate Exceeded HOEP

Year	Hours	% of Year	Reg. Rate	Comments
2012	8519	97	51.52	
2013	8425	96	51.52	
2014	7462	85	51.52/59.29	Rate change Nov. 1, 2014
2015	8363	95	59.29	
2016	6451	98	59.29	YTD Sept. 30, 2016

GEC Interrogatory #63

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

Interrogatory

Reference:

Please confirm that the customer impacts on Slide 9 of the September 23rd rate smoothing presentation do not include the impacts on customer total bills of expected coincident changes in generation costs incurred by the system overall (for example due to replacement generation and carbon fees). If OPG has considered this or has information from others that have considered this context, please provide.

Response

OPG confirms that the customer impacts on Slide 9 of the September 23rd rate smoothing presentation do not include impacts on customer total bills of expected coincident changes in generation costs incurred by the system overall. The customer impacts included in this slide rely on the same assumptions outlined in Ex.I1-1-2 Tables 1 and 2.

GEC Interrogatory #64

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

Interrogatory

Reference:

Please estimate the impact on payments and customer rates in each year of the 20 year deferral and recovery period, with and without the smoothing proposal, should the government require the exercise of an off-ramp in regard to the DRP at the completion of Unit 2 refurbishment.

Response

OPG is unable to provide the requested estimate and doesn't believe it is relevant to any issue on the approved Issues List. The costs that would be incurred if an off-ramp were to be exercised would depend on the timing of the decision and the specific direction from the Government regarding the future operation of Darlington. Any attempt to calculate 20 years of payment amounts without this information would be speculative, as it would be entirely dependent on assumptions that have no basis in fact. In the event the Government exercises an off-ramp during the period covered by this application, OPG would inform the OEB and seek direction.

GEC Interrogatory #65

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

Interrogatory

Reference:

Please estimate the impact on payments and customer rates in each year of the 20 year deferral and recovery period, with and without the smoothing proposal for a 25%, 50% and 100% cost overrun on the DRP and a 1 year, 2 year and 3 year delay in unit 2 return to service and logical combinations of these (as we assume a delay would also entail increased costs).

Response

In this response, OPG provides the payment amounts and customer bill impacts that result from six scenarios:

1. 25% DRP cost overrun, with rate smoothing at 11% annually during the deferral period
2. 25% DRP cost overrun, without rate smoothing
3. 100% DRP cost overrun, with rate smoothing at 11% annually during the deferral period
4. 100% DRP cost overrun, without rate smoothing
5. 25% DRP cost overrun and a one-year delay in Unit 2 returning to service, with rate smoothing at 11% annually during the deferral period
6. 25% DRP cost overrun and a one-year delay in Unit 2 returning to service, without rate smoothing

The impacts of each scenario are presented in each of the three tables provided in Attachment 1. Table 1 shows the nuclear payment amounts, Table 2 shows the annualized residential consumer impact, and Table 3 shows the 20 year average bill impact.

Scenarios 5 and 6 assume that the subsequent Units are refurbished on the same schedule and following the same duration assumptions reflected in the pre-filed evidence, offset by one year due to Unit 2's delayed return to service.

Given the significant work required to produce each scenario, OPG cannot provide remaining scenarios with reasonable effort. OPG has provided these six scenarios because they span the range of circumstances in the question. For the period beyond the 2017-2021 IR Term, the tables in this response use the same five-year intervals as provided in Ex. A1-3-3 Chart 2.

In OPG's view, none of the scenarios are a reasonable representation of any likely outcome of the DRP. In addition, these scenarios do not account for any costs that would be borne by contractors, since those amounts would depend on the specific circumstances of any overrun or delay. Consequently, OPG expects that actual payment amounts and customer bill impacts would be lower than those shown in this response in the event of a cost overrun or delay.

Numbers may not add due to rounding.

Table 1
Nuclear Payment Amounts ($/MWh)

Line No		2017	2018	2019	2020	2021	Average 2022-2026	Average 2027-2031	Average 2032-2036
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	25% Cost Over Run (Smoothed)	65.81	73.05	81.09	90.01	99.91	138.13	161.60	150.90
2	100% Cost Over Run (Smoothed)	65.81	73.05	81.09	90.01	99.91	138.13	187.52	223.97
3	25% Cost Over Run + Delay (Smoothed)[1]	65.81	73.05	81.09	90.01	99.91	146.25	170.88	146.99
4	25% Cost Over Run (Unsmoothed)	84.00	84.36	83.68	103.14	100.90	145.92	144.75	130.19
5	100% Cost Over Run (Unsmoothed)	84.82	83.92	82.16	109.38	107.72	166.47	175.44	156.52
6	25% Cost Over Run + Delay (Unsmoothed)[1]	84.00	84.36	82.94	89.51	93.14	164.87	139.88	135.14

Notes:
1 Scenario includes a one year delay in Unit 2 and extends deferral period and recovery period out by one year. Column (f) covers 2022-2027, column (g) covers 2028-2032, column (h) covers 2033-2037

Numbers may not add due to rounding.

Table 2
Annualized Residential Consumer Impact

Line No		2017	2018	2019	2020	2021	Average 2017-2021
		(a)	(b)	(c)	(d)	(e)	(f)
	SMOOTHED						
	25% cost over run						
1	Typical Bill Impact ($/Month)	(1.29)	1.73	1.07	1.86	1.89	1.05
2	Typical Bill Impact (%)	-0.9%	1.1%	0.7%	1.2%	1.3%	0.7%
	100% cost over run						
3	Typical Bill Impact ($/Month)	(1.29)	1.73	1.07	1.86	1.89	1.05
4	Typical Bill Impact (%)	-0.9%	1.1%	0.7%	1.2%	1.3%	0.7%
	25% cost over run + delay						
5	Typical Bill Impact ($/Month)	(1.29)	1.73	1.11	1.59	2.76	1.18
6	Typical Bill Impact (%)	-0.9%	1.1%	0.7%	1.1%	1.8%	0.8%
	UNSMOOTHED						
	25% cost over run						
7	Typical Bill Impact ($/Month)	2.69	0.23	(0.87)	4.11	(0.64)	1.10
8	Typical Bill Impact (%)	1.8%	0.2%	-0.6%	2.7%	-0.4%	0.7%
	100% cost over run						
9	Typical Bill Impact ($/Month)	2.87	(0.05)	(1.11)	5.78	(0.56)	1.39
10	Typical Bill Impact (%)	1.9%	0.0%	-0.7%	3.8%	-0.4%	0.9%
	25% cost over run + delay						
11	Typical Bill Impact ($/Month)	2.69	0.23	(1.00)	1.09	1.35	0.87
12	Typical Bill Impact (%)	1.8%	0.2%	-0.7%	0.7%	0.9%	0.6%

Table 3

Average Nuclear Bill Impact (2017-2036)

Line No		2017-2036
	SMOOTHED	
	25% cost over run	
1	Typical Bill Impact ($/Month)	0.63
2	Typical Bill Impact (%)	0.4%
	100% cost over run	
3	Typical Bill Impact ($/Month)	1.38
4	Typical Bill Impact (%)	0.9%
	25% cost over run + delay[1]	
5	Typical Bill Impact ($/Month)	0.53
6	Typical Bill Impact (%)	0.3%
	UNSMOOTHED	
	25% cost over run	
7	Typical Bill Impact ($/Month)	0.52
8	Typical Bill Impact (%)	0.3%
	100% cost over run	
9	Typical Bill Impact ($/Month)	0.74
10	Typical Bill Impact (%)	0.5%
	25% cost over run + delay[1]	
11	Typical Bill Impact ($/Month)	0.47
12	Typical Bill Impact (%)	0.3%

GEC Interrogatory #66

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

Interrogatory

Reference:

Please quantify the impact on nuclear payments and customer bills with and without rate smoothing if in this application we assume that Pickering life extension will not obtain CNSC approval or otherwise will not proceed and the implications if this unexpectedly arises subsequent to rates being set.

Response

OPG is unable to provide the requested estimate and does not believe that it is relevant to any issue on the approved Issues List. Any attempt to forecast payment amounts or customer bills assuming that Pickering Extended Operations would not obtain CNSC approval would be speculative as costs would depend on the specifics of the CNSC decision in terms of the required shutdown dates for the individual Pickering units, and the actions required to continue operating each unit until its required shutdown date. Similarly, the cost consequences of some other unspecified event that causes OPG not to proceed with Pickering Extended Operations are impossible to determine. For the hypothetical rate impact associated with the previously assumed 2020 shutdown date, see Ex. L-11.2-1 Staff-263.

OAPPA Interrogatory #1

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

***Issue Number: 2.2 (part b)**
Issue: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

Interrogatory

Item 1: Have ratepayers been sufficiently informed and to what extend does the DRP create financial obligations for future ratepayers beyond the Test Period.

1-OAPPA-1

Reference:
Re: Exhibit D2-2-1, Darlington Refurbishment Program Overview, page 2, lines 13 – 15, footnote #1 Exhibit A1-2-1, Application, Page 4, line 1
Exhibit A2-2-1, Attachment 1, "OPG's 2016-2018 Business Plan", Unlabeled Chart, page 5 of27)

The DRP Overview Exhibit advises that the Minister of Energy formally endorsed the project in January 2016, and further provided a footnote link to the Provincial Government's Newsroom release from the Ministry of Energy. While the release identified the expected budget of $12.8B, consistent with the Application, it also states "OPG electricity rates are regulated by the Ontario Energy Board (OEB). All costs for the Darlington refurbishment will be subject to review and approval by the OEB through a public and transparent process to ensure they are prudently incurred. The average cost of power from Darlington nuclear units post-refurbishment is estimated to range between $72/MWh and $81/MWh, or 7 and 8 cents per kilowatt hour". Familiar with the release prior to its Exhibit reference, we were therefore surprised to find that the requested nuclear rates in the Application for 2020 and 2021 are $90.01/MWh and $99.91/MWh, respectively. We note that these requested rates also include the lower depreciated rates of Pickering NGS and further note that the DRP will have only seen the completion of Darlington Unit 2 refurbishment by the end of the Test Period (but potentially with some progress expenses incurred for Units 3 and 1).

a) Can you please provide the Nuclear Payment amount request table, differentiating the Darlington and Pickering-specific rates, for each of the years of the Test Period? Can you provide similarly for the post-Test Period?

b) Was sufficient information concerning the actual nuclear rate impacts provided to the Ministry before their endorsement was received?

c) Please confirm that if the Board approves OPG's revenue requirements as filed and agrees to the proposed smoothing methodology for OPG's nuclear rates: the nuclear rate will continue to increase at a rate of 11.1% per year, in each of the 5 years following the Test Period (declining thereafter)? Would the expected nuclear rates, before riders, be as follows: $111/MWh, $123.3/MWh, $137/MWh, $152.2/MWh and $169.1/MW, respectively between 2021 and 2026?

Response

a) The OEB has determined to set the payment amounts for the prescribed facilities on a technology specific basis (i.e., one payment amount for hydroelectric and one for nuclear). Therefore, OPG does not compute or collect payment amounts on a plant specific basis. The proposed Nuclear Payment amounts are provided at Ex. I1-3-1 Table 1, line 11.

b) OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on communications with the Province of Ontario that is not relevant to deciding any issue on the approved Issues List in this application. An investigation into the Province's decision to endorse Darlington Refurbishment is not within the scope of this proceeding because O. Reg. 53/05 s. 6(2)(12)(v) states: "the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment"

c) OPG has not included a request for payment amounts beyond 2021 in this application. As stated in Ex. A1-3-3, OPG proposes an 11 per cent annual smoothed rate increase for the 2017-2021 period. OPG has provided an illustrative view of the rate smoothing proposal in Ex. A1-3-3 that assumes the 11 percent smoothed rate increase will continue for the 2022-2026 period, resulting in a rate decrease each year from 2027-2036. The resulting illustrative smoothed rates are provided in Ex. L-11.6-7 ED-24. The information provided for 2022-2036 is for illustrative purposes only and does not represent a request for approval of payment amounts in the 2022-2026 period. OPG intends to address its request for smoothed payment amounts for the 2022-2026 period in a subsequent application for nuclear payment amounts.

OAPPA Interrogatory #3

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

Interrogatory
Issue 2: Seeking clarifying regulated revenue source payments, hydraulic revenue amounts and ability to influence non-regulated revenue via regulated asset control.

2-OAPPA-1

Reference:
Ref: Exhibit B1-1-1, Section 2.0 Overview and Table 1 (or Exhibit I1-1-2, Table 11)
Exhibit A2-1-1, Attachment 3, "*OPG's 2015 Annual Report*", Pages 11, 12, 13 (Page 5, 7, 8 of Report)

Acknowledging that OPG earns its regulated revenues firstly from the IESO-controlled Hourly Ontario Electricity Price (HOEP), monthly wholesale market payments and then as true-up from the monthly Global Adjustment payments, for each of the years of the Test Period:

a) What will be the approximate percentage split between HOEP-revenue and GA-revenue for each of (1) nuclear and (2) hydraulic?

b) Summary information for nuclear is well presented and readily located, but hydraulic revenue is difficult to discern. Can you please confirm payment amounts for regulated Hydraulic, in addition to those requested for nuclear, are as follows:

	2017	2018	2019	2020	2021
Revenue Request	$1,304	$1,323	$1,299	$1,318	$1,338

In 2015, OPG's contracted, non-regulated generation revenue was $264 million of its total $689 million, or ~ 38% of its total annual revenue. Conversely, electricity generated from the contacted generation was only 3.1 TWh of its total production of 78 TWh, or ~ 4% of its total production.

c) What is the approximate split of these contracted revenues between Global Adjustment payments and HOEP earnings?

d) When the Thunder Bay G.S. contracted generation agreement expires during the Test Period, is it management's expectation that it will be re-contracted or will it become part of the regulated generation assets?

e) What assurances can management provide that as the dominant electricity producer in the province, that its regulated nuclear and hydraulic generation assets are not being used to influence HOEP in a manner that benefits its non-regulated revenue?

Response

a) OPG declines to provide the response as the calculation requested requires the use of OPG's proprietary forecast of HOEP. Projections of HOEP and Global Adjustment are the purview of the IESO.

b) As outlined in section 2 of Ex. A1-3-2, OPG is not seeking approval of a revenue requirement for Hydroelectric. The payment amount approvals that OPG is seeking for Hydroelectric are items 5 and 6 of Ex. A1-2-2.

c) OPG's contracted assets are not prescribed under section 78.1 of the Ontario Energy Board Act and therefore not regulated by the Ontario Energy Board.

d) Thunder Bay GS is not a prescribed generation facility under section 78.1 of the Act.

e) As a market participant in the Province of Ontario, OPG is subject to the IESO's Market Rules for the Ontario Electricity Market. The IESO's Market Assessment and Compliance Division (MACD) enforces the market rules while the OEB's Market Surveillance Panel (MSP) is responsible for market monitoring and for investigation of activities which may constitute abuses of market power by market participants. MSP issues monitoring reports on the IESO-administered electricity market on a semi-annual basis.

OAPPA Interrogatory #5

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

Interrogatory

Item 3: Is the cost sharing between ratepayers and shareholders fair and properly allocated and is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact to customers.

3-OAPPA-2

Reference:

Re: Exhibit I1-1-2, Consumer Impact, Chart 1, Page 2, Table 1 and Attachment 1, Table 11

OPG's annualized residential consumer bill impacts are calculated as if there is only one common consumer rate class, which we believe to be understated. Using this same methodology, the following is the Customer Impact Table for OAPPA for the 5-year period.

OPG Rate Impact on OAPPA	OAPPA				
	2017	2018	2019	2020	2021
	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016	OPG Proposed 5/27/2016
Annual OAPPA Total Cost $ (1) (2)	$ 182,079,599	$ 182,079,599	$ 182,079,599	$ 182,079,599	$ 182,079,599
OPG's Annual Rate Impact on OAPPA $	$ (1,715,672)	$ 2,290,028	$ 1,403,520	$ 2,507,234	$ 2,616,467
Total OAPPA Annual Cost $	$ 180,363,926	$ 184,369,626	$ 183,483,118	$ 184,586,833	$ 184,696,065
Cummulative Increase on OAPPA	$ (1,715,672)	$ 574,355	$ 1,977,875	$ 4,485,109	$ 7,101,576
Cummulative Unit Cost $/MWh Increase on OAPPA	$ (1.63)	$ 0.55	$ 1.88	$ 4.27	$ 6.76

(1) OAPPA Annual Consumption 1,050,338MWh including line losses
(2) Typical monthly bill is based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility.
Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.
Calculated based on OPG_Ex I1-1-1_Att 1_OPG_Revenue Requirement Work Form_20160527 -OPG Bill Impacts - Spreadsheet 11

However, since January 1, 2011, there have been two broad rate classes: customers in the Global Adjustment Class A and customers in the Global Adjustment Class B. Residential consumers are in Class B. By virtue of the different cost allocation methods used for the two classes, Class B pays a higher share of Global Adjustment costs than does Class A and so would experiences a higher rate impact than other Class A customers. OPG rate impacts will affect the Global Adjustment costs and the result is that OPG's single-class method underestimates the magnitude of certain consumer bill impacts.

a) Please provide an accurate portrayal of the bill impacts over the Test Period, accounting for the difference in Global Adjustment treatments, for three typical consumer classes (1) residential, (2) commercial general service, and (3) large consumer. If possible, the last consumer classification should include those estimated amounts, that would now be covered by the province's September 14, 2016 provincial government announcement[1], expanding the Industrial Conservation Incentive (and Class A consumer coverage), expected to take effect July 1, 2017.

[1] http://www.energy-manager.ca/news/ontario-expanding-industrial-conservation-initiative-2740

Response

OPG does not have the necessary information to determine the global adjustment, please refer to L-1.3-5 CCC 9 for a description of OPG's ability to produce the annualized consumer impacts presented in Ex. I1-2-1.

SEC Interrogatory #6

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

Interrogatory

Reference:

Attached is a spreadsheet setting out the nuclear and hydroelectric payment amounts, actual and proposed, for the period 2011 to 2026 inclusive, together with calculations of the impacts of those payment amounts on Ontario schools. To ensure that the impacts only reflect increases in OPG charges, school consumption has been kept constant at the 2013 BPS (Broader Public Service) reported volumes, and the split between hydroelectric and nuclear consumption has also been kept constant. In answering this interrogatory, please assume that the volumes for schools are correct. The rider for rate smoothing has been treated as part of base rates, rather than a separate rider. All other riders are treated as riders rather than base rates. The forecasts assume that the OPG's new payment amounts order is dated and effective January 1, 2017.

With respect to the spreadsheet and the impacts of the application on Ontario schools:

1. Please confirm that the payment amounts inserted in the spreadsheet are correct, and the calculations, based on those payment amounts are correct.

2. Please complete the years 2022-2026 for the Unsmoothed Rates with no Riders category using the OPG's most current estimates of those rates. If those estimate are not the same as the estimated used to estimate the smoothed rates of 11% annually for ten years, please explain the differences.

3. Please complete all years 2011-2026 for the Smoothed and Unsmoothed Rates with and without Riders, using the OPG's actual and forecast riders for 2011-2016, and the OPG's most current estimate of riders for all subsequent periods.

4. Please confirm that, under the OPG's proposal:

   a. Ontario schools can expect to pay, in base payment amounts, $79.5 million per annum more in 2026 than in 2011, a compounded annual growth rate in payment amounts to OPG of 6.7% per year for fifteen years. If that is not correct, please provide the correct calculation. Please calculate the same figure including rate riders.

   b. Ontario schools can expect to pay, in base payment amounts for nuclear, $74.3 million per annum more in 2026 than in 2011, a compounded annual growth rate in payment amounts to OPG of 8.2% per year for fifteen years. If that is not correct, please provide the correct calculation. Please calculate the same figure including rate riders.

c. Ontario schools can expect to pay, in base payment amounts, $72.4 million per annum more in 2026 than in 2061, a compounded annual growth rate in payment amounts to OPG of 8.7% per year for ten years. If that is not correct, please provide the correct calculation. Please calculate the same figure including rate riders.

d. Ontario schools can expect to pay, in base payment amounts for nuclear, $69.4 million per annum more in 2026 than in 2016, a compounded annual growth rate in payment amounts to OPG of 11.0% per year for ten years. If that is not correct, please provide the correct calculation. Please calculate the same figure including rate riders.

e. The OPG is proposing that, on average, Ontario schools should pay amounts for OPG generation each year over the next ten years that are 61.4% higher than 2016 payment amounts for the same amount of generation.

5. Please provide all examples in the possession of the OPG showing comparable long-term increases in generation rates for customers, and details surrounding the reasons for those increases. Please provide a comparison of the increases proposed by the OPG to the increases proposed (or charged) by the comparators.

Response

1. OPG confirms that the payment amounts inserted in the spreadsheet are correct for 2012, 2013, and 2016. In addition the proposed smoothed payment amounts for 2017-2021, and the illustrative unsmoothed payment amounts for 2017-2021 are correct.

   For the following payment amounts in the spreadsheet:
   - 2011 nuclear payment amounts were $51.52 beginning March 1, 2011, however; they were $52.98 for January and February of 2011.
   - 2011 hydroelectric payment amounts were $35.78 beginning March 1, 2011, however; they were $36.66 for January and February of 2011.
   - OPG has never had a payment amount of $37.57 approved for hydroelectric, OPG cannot confirm the 2014 hydroelectric payment amount referred to in the spreadsheet. 2014 payment amounts were $51.52 for January – October of 2014, however the payment amount of $59.29 became effective November 1st, 2014.
   - 2015 payment amounts were $59.29, not $51.52.
   - OPG has not proposed payment amounts for 2022-2026.

   OPG has reviewed the attached spreadsheet but cannot confirm whether the calculations performed by SEC (i.e., the assessment of the impact of OPG's proposed payment amounts on schools) are correct or complete. OPG is not familiar with the source(s) of the data or the methodology used by SEC to perform this calculation.

2. OPG has provided an estimate of the revenue requirements and production for the 2022-2026 period in Ex. A1-3-3. Chart 2 of this exhibit provides an average rate of $139/MWh for 2022-2026 absent rate smoothing. For a more detailed chart, see Ex. L-09.7-15 SEC-093.

3. Table 1 of attachment 1 provides the Nuclear payment amounts and riders from 2011-2021 (as approved in prior proceedings, or as proposed in this application). OPG has not forecast riders for the 2019-2021 period. As discussed in response to part 1, OPG has not proposed annual rates or riders (smoothed or unsmoothed) for the 2022-2026 period, however; illustrative rates are provided in response to Ex. L-09.7-15 SEC-093.

4. As discussed in response to part 1, OPG does not have the knowledge to provide or assess bill impacts for Ontario schools. In addition, and as discussed above, OPG has not proposed rates for the years 2022-2026 and as such cannot asses or speculate as to what the impact to schools will be in 2026.

5. To assess the magnitude of a long term increase in generation rates, information would be required on previous and newly regulated contracts with unregulated commercial companies. This type of information is not typically publicly available and as such OPG does not have such examples.

Numbers may not add due to rounding

SEC ATTACHMENT #1

Table 1
OPG Nuclear Payment Amounts

	Nuclear Payment Amount															
	O.Reg 53/05	**EB-2007-0905**	**EB-2010-0008**	**EB-2012-0002**		**EB-2013-0321**		**EB-2014-0370**			**EB-2016-0152 (Proposed)**				
Effective Date	1-Apr-05	1-Apr-08	1-Mar-11	1-Jan-13	1-Jan-14	1-Nov-14	1-Jan-15	1-Jul-15	1-Oct-15	1-Jan-16	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20	1-Jan-21
Base Payment Amount ($/MWh)	$ 49.50	$ 52.98	$ 51.52	$ 51.52	$ 51.52	$ 59.29	$ 59.29	$ 59.29	$ 59.29	$ 59.29	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
D&V Rider ($/MWh)	$ -	$ 2.00	$ 4.33	$ 6.27	$ 4.18	$ 4.18	$ 1.33	$ 12.17	$ 14.34	$ 13.01	$ 2.85	$ 2.85			

Impacts of 2017-2021 Rate Application on Schools

Annual Consumption Assumptions for Schools (From BPS Energy Reporting 2013 data)

Nuclear	636,240	MwH
Reg. Hydro	434,472	MwH
Total	1,070,712	MwH

Smoothed Rates with no Riders

	2011	2012	2013	2014	2015	2016	Total	2017	2018	2019	2020	2021	Total	2022	2023	2024	2025	2026	Total	Ten years
Nuclear	$51.52	$51.52	$51.52	$51.52	$51.52	$59.29		$65.81	$73.05	$81.09	$90.01	$99.91		$110.90	$123.10	$136.64	$151.67	$168.35		
Dollars	$32,779	$32,779	$32,779	$32,779	$32,779	$37,723	$168,839	$41,871	$46,477	$51,593	$57,268	$63,567	$260,776	$70,559	$78,321	$86,936	$96,499	$107,111	$439,426	$700,201
% change		0.00%	0.00%	0.00%	0.00%	15.08%		11.00%	11.00%	11.01%	11.00%	11.00%		11.00%	11.00%	11.00%	11.00%	11.00%		
Hydro	$35.78	$35.78	$35.78	$37.57	$40.72	$40.72		$41.71	$42.33	$42.97	$43.61	$44.27		$44.93	$45.61	$46.29	$46.99	$47.69		
Dollars	$15,545	$15,545	$15,545	$16,323	$17,692	$17,692	$82,797	$18,122	$18,391	$18,669	$18,947	$19,234	$93,364	$19,523	$19,815	$20,113	$20,414	$20,721	$100,586	$193,949
% change		0.00%	0.00%	5.00%	8.38%	0.00%		2.43%	1.49%	1.51%	1.49%	1.51%		1.50%	1.50%	1.50%	1.50%	1.50%		
Blended	$45.13	$45.13	$45.13	$45.86	$47.14	$51.75		$56.03	$60.58	$65.62	$71.18	$77.33		$84.13	$91.66	$99.98	$109.19	$119.39		
Dollars	$48,324	$48,324	$48,324	$49,102	$50,471	$55,414	$251,636	$59,993	$64,869	$70,262	$76,215	$82,801	$354,139	$90,082	$98,137	$107,048	$116,913	$127,832	$540,011	$894,150
% change		0.00%	0.00%	1.61%	2.79%	9.79%		8.26%	8.13%	8.31%	8.47%	8.64%		8.79%	8.94%	9.08%	9.21%	9.34%		
Increase		$0	$0	$778	$2,146	$7,090	$10,014	$4,578	$9,454	$14,848	$20,801	$27,386	$77,068	$34,667	$42,722	$51,634	$61,498	$72,417	$262,939	$340,007

Unsmoothed Rates with no Riders

	2011	2012	2013	2014	2015	2016	Total	2017	2018	2019	2020	2021	Total
Nuclear	$51.52	$51.52	$51.52	$51.52	$51.52	$59.29		$83.73	$84.48	$84.17	$101.05	$98.61	
Dollars	$32,779	$32,779	$32,779	$32,779	$32,779	$37,723	$168,839	$53,272	$53,750	$53,552	$64,292	$62,740	$287,606
% change		0.00%	0.00%	0.00%	0.00%	15.08%		41.22%	0.90%	-0.37%	20.05%	-2.41%	
Hydro	$35.78	$35.78	$35.78	$37.57	$40.72	$40.72		$41.71	$42.33	$42.97	$43.61	$44.27	
Dollars	$15,545	$15,545	$15,545	$16,323	$17,692	$17,692	$82,797	$18,122	$18,391	$18,669	$18,947	$19,234	$93,364
% change		0.00%	0.00%	5.00%	8.38%	0.00%		2.43%	1.49%	1.51%	1.49%	1.51%	
Blended	$45.13	$45.13	$45.13	$45.86	$47.14	$51.75		$66.68	$67.38	$67.45	$77.74	$76.56	
Dollars	$48,324	$48,324	$48,324	$49,102	$50,471	$55,414	$251,636	$71,394	$72,141	$72,222	$83,239	$81,974	$380,970
% change		0.00%	0.00%	1.61%	2.79%	9.79%		28.84%	1.05%	0.11%	15.26%	-1.52%	
Increase		$0	$0	$778	$2,146	$7,090	$10,014	$15,980	$16,726	$16,807	$27,825	$26,559	$103,898

Smoothed Rates with Riders

	2016	2017	2018	2019	2020	2021
Nuclear	$59.29	$65.81	$73.05	$81.09	$90.01	$99.91
Rider						
Total						
Dollars						
% change						
Hydro	$40.72	$41.71	$42.33	$42.97	$43.61	$44.27
Rider						
Total						
Dollars						
% change						
Blended	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Rider						
Total						
Dollars						
% change						

Unsmoothed Rates with Riders

	2016	2017	2018	2019	2020	2021
Nuclear	$59.29	$65.81	$73.05	$81.09	$90.01	$99.91
Rider						
Total						
Dollars						
% change						
Hydro	$40.72	$41.71	$42.33	$42.97	$43.61	$44.27
Rider						
Total						
Dollars						
% change						

Blended Rider Total Dollars % change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00