Issue Number: 1.1

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

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).

Witness Panel: Overview, Rate-setting Framework
1. Updates and clarifies reporting and communication expectations (s. 5).
2. 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
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<thead>
<tr>
<th>CONTACT INFORMATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>If you require further information on business planning assumptions, schedules, or requirements, please contact:</td>
</tr>
<tr>
<td>Anthony Melaragno – Senior Manager, Financial Forecasts 400-4646</td>
</tr>
<tr>
<td>Vassa Chase – Director, Business Planning &amp; Regulatory Finance 400-3272</td>
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<tr>
<td>Alex Kogan – Vice-President, Business Planning &amp; Reporting 400-3103</td>
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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 needsto 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

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

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

<table>
<thead>
<tr>
<th>2017-2019 Business Plan Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pickering</strong></td>
</tr>
<tr>
<td>• End of life for Pickering Units 1 and 4 at the end of 2022 and Units 5-8 at the end of 2024</td>
</tr>
<tr>
<td>• Pickering operating licence renewal in 2018 spans the Pickering Extended Operations period</td>
</tr>
<tr>
<td>• Pickering Extended Operations enabling activities are carried out consistent with the approved business case</td>
</tr>
<tr>
<td>• 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</td>
</tr>
<tr>
<td>• Vacuum Building outage in 2021 (30-day outage for all six units)</td>
</tr>
<tr>
<td>• Preparation activities required to directly support the safe storage of the units will be funded from the nuclear Decommissioning Segregated Fund</td>
</tr>
<tr>
<td><strong>Darlington</strong></td>
</tr>
<tr>
<td>• Outage plan is based on all units meeting the refurbishment schedule without idle time</td>
</tr>
<tr>
<td>• The Unit 2 Turbine Generator Controls replacement takes place in 2022</td>
</tr>
<tr>
<td>• Post-refurbishment performance of Unit 2 reflects industry operating experience</td>
</tr>
<tr>
<td>• Plant investments take into consideration life cycle plans and regulatory requirements and commitments, and are aligned with the refurbishment</td>
</tr>
<tr>
<td>• During the business planning period, planning efforts continue to permit the life extension of the Tritium Removal Facility</td>
</tr>
<tr>
<td><strong>Darlington Refurbishment</strong></td>
</tr>
<tr>
<td>• The refurbishment outage for the first unit (Unit 2) commences in October 2016 and is completed by February 2020</td>
</tr>
<tr>
<td>• 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</td>
</tr>
<tr>
<td><strong>Nuclear Waste Management</strong></td>
</tr>
<tr>
<td>• Assumed receipt of currently pending construction licence enables the L&amp;ILW DGR to be targeted for in-service approximately at the end of 2025</td>
</tr>
<tr>
<td>• 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</td>
</tr>
<tr>
<td>• Loading of dry storage containers is maintained at the Darlington and Pickering Waste Management Facilities, and at a sustainable level for Bruce Power</td>
</tr>
<tr>
<td>• Used fuel and L&amp;ILW volumes from the Bruce units are based on information as received from Bruce Power; non-routine refurbishment L&amp;ILW is not reflected pending completion of necessary agreements</td>
</tr>
<tr>
<td><strong>Nuclear New Build</strong></td>
</tr>
<tr>
<td>• 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</td>
</tr>
</tbody>
</table>
## 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

### Hydroelectric
- **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.
- **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** redevelopment begins in 2018, with an in service date of December 2020 for both facilities, as part of regulated assets.
- Incremental expenditures related to the implementation of Provincial Dam Safety Technical Guidelines to be considered.

### Thermal
-
2017-2019 Business Plan Assumptions (cont’d)

<table>
<thead>
<tr>
<th>Business and Administrative Services</th>
<th>Shareholder-directed sale of OPG’s Headquarters property (and associated leaseback) takes place effective beginning of April 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IT Cyber Security costs are planned by the BAS organization</td>
</tr>
<tr>
<td></td>
<td>Real Estate &amp; Services is accountable for facility requirements outside the protected areas, including roads and bridges</td>
</tr>
</tbody>
</table>

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:
  - Pickering – December 31, 2020
  - 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.

<table>
<thead>
<tr>
<th>Earnings Before Interest and Taxes for Generation Segments ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>$millions</strong></td>
</tr>
<tr>
<td>Regulated – Nuclear Generation ²</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Regulated – Hydroelectric ³</td>
</tr>
</tbody>
</table>

**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.

<table>
<thead>
<tr>
<th>Regular Headcount Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Targets</strong></td>
</tr>
<tr>
<td>Total Nuclear (Excl. Darlington Refurbishment)</td>
</tr>
<tr>
<td>Nuclear Projects</td>
</tr>
<tr>
<td>Nuclear Operations</td>
</tr>
<tr>
<td>Renewable Generation &amp; Power Marketing</td>
</tr>
<tr>
<td><strong>Total Operations</strong></td>
</tr>
<tr>
<td>Business and Administrative Services</td>
</tr>
<tr>
<td>Finance</td>
</tr>
<tr>
<td>Assurance</td>
</tr>
<tr>
<td>People/Culture &amp; Communications</td>
</tr>
<tr>
<td>Legal/Ethics &amp; Compliance</td>
</tr>
<tr>
<td>Corporate Office</td>
</tr>
<tr>
<td><strong>Total Support Services</strong></td>
</tr>
<tr>
<td><strong>Total Ongoing Operations</strong></td>
</tr>
<tr>
<td><strong>Darlington Refurbishment</strong></td>
</tr>
<tr>
<td><strong>Total OPG</strong></td>
</tr>
</tbody>
</table>
### Total OM&A Targets*

<table>
<thead>
<tr>
<th></th>
<th>$ millions</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nuclear</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear Project Portfolio (Excl. Darlington Refurbishment)</td>
<td>1,719</td>
<td>1,729</td>
<td>1,764</td>
<td></td>
</tr>
<tr>
<td>Nuclear Operations - Base &amp; Outage OM&amp;A</td>
<td>114</td>
<td>109</td>
<td>100</td>
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</tr>
<tr>
<td><strong>Renewable Generation &amp; Power Marketing</strong></td>
<td>1,605</td>
<td>1,620</td>
<td>1,664</td>
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</tr>
<tr>
<td><strong>Total Base OM&amp;A</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulated Plants Project OM&amp;A</td>
<td>79</td>
<td>88</td>
<td>99</td>
<td></td>
</tr>
<tr>
<td><strong>Total Operations</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Business and Administrative Services</td>
<td>295</td>
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</tr>
<tr>
<td>Base OM&amp;A</td>
<td>279</td>
<td>276</td>
<td>279</td>
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<tr>
<td>Project OM&amp;A</td>
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<td>13</td>
<td>13</td>
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</tr>
<tr>
<td>Finance</td>
<td>79</td>
<td>78</td>
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<tr>
<td>Insurance</td>
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<tr>
<td>Assurance</td>
<td>12</td>
<td>11</td>
<td>12</td>
<td></td>
</tr>
<tr>
<td>People/Culture &amp; Communications</td>
<td>133</td>
<td>131</td>
<td>133</td>
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</tr>
<tr>
<td>Legal/Ethics &amp; Compliance</td>
<td>33</td>
<td>31</td>
<td>33</td>
<td></td>
</tr>
<tr>
<td>Corporate Office</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td></td>
</tr>
<tr>
<td><strong>Total Support Services</strong></td>
<td>604</td>
<td>597</td>
<td>606</td>
<td></td>
</tr>
<tr>
<td><strong>Total Ongoing Operations</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Darlington Refurbishment**</td>
<td>42</td>
<td>14</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Nuclear New Build</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td><strong>Total OPG</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*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

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

*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

<table>
<thead>
<tr>
<th>$ millions</th>
<th>Targets</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nuclear Project Portfolio (Excl. Darlington Refurbishment)</strong></td>
<td>114</td>
<td>109</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Renewable Generation &amp; Power Marketing - Regulated Plants</td>
<td>79</td>
<td>88</td>
<td>99</td>
<td></td>
</tr>
<tr>
<td>Renewable Generation &amp; Power Marketing - Other Projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Renewable Generation &amp; Power Marketing</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Business and Administrative Services</td>
<td>16</td>
<td>13</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>Legal/Ethics &amp; Compliance</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td><strong>Total Support Services</strong></td>
<td>17</td>
<td>13</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>Darlington Refurbishment</td>
<td>42</td>
<td>14</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Nuclear New Build</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td><strong>Total OPG</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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.

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

<table>
<thead>
<tr>
<th></th>
<th>$ millions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Darlington Refurbishment Retube Waste Containers</td>
<td>32 43 30</td>
</tr>
<tr>
<td>Nuclear Waste Management</td>
<td>40 40 40</td>
</tr>
<tr>
<td><strong>Total Nuclear Decommissioning and Waste Management Expenditures</strong></td>
<td><strong>72 83 70</strong></td>
</tr>
</tbody>
</table>

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

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

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

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**

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.

<table>
<thead>
<tr>
<th>MONTH</th>
<th>BUSINESS PLANNING ACTIVITY</th>
</tr>
</thead>
</table>
| 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 [supplementary financial information](#) 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 [supplementary financial information](#) 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
  - 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, environmental, 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
  o BU’s 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:
  o 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 PEXIT 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 PEXIT projects for this year’s plan and should reassign their base plan from Project 82828 to Project 00000 in BPC.

For reference, the PEXIT 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.

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

*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]
Northeast Operations – excluding
Northwest Operations – excluding

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

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.

<table>
<thead>
<tr>
<th>ITEM</th>
<th>BUSINESS PLANNING ACCOUNTABILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation/Amortization – <em>July 25</em>&lt;br&gt; o 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</td>
<td>Finance – Shared Financial Services – Accounting</td>
</tr>
<tr>
<td>Property Tax (separately showing amounts to be charged against decommissioning provisions and amount to be capitalized) – <em>July 25</em></td>
<td>BAS – Real Estate &amp; Services – Property Assessment and Taxation</td>
</tr>
<tr>
<td>Insurance – July 25</td>
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<tr>
<td>---------------------</td>
<td></td>
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<tr>
<td>Summary of underlying assumptions</td>
<td></td>
</tr>
<tr>
<td>Amounts to be charged against decommissioning provisions and amounts to be capitalized to be shown separately</td>
<td></td>
</tr>
<tr>
<td>Finance – Treasury (costs submitted as part of the Finance BPC submission)</td>
<td></td>
</tr>
<tr>
<td>Employee incentive plans (centrally-held cost) – July 25</td>
<td></td>
</tr>
<tr>
<td>PC&amp;C – Total Rewards &amp; Solutions Centre</td>
<td></td>
</tr>
<tr>
<td>Vacation accrual and fiscal calendar adjustment (centrally-held costs) – July 25</td>
<td></td>
</tr>
<tr>
<td>Finance – Shared Financial Services – Accounting</td>
<td></td>
</tr>
<tr>
<td>Pension Guarantee Fee (centrally-held cost) – July 25</td>
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<tr>
<td>Finance – Treasury</td>
<td></td>
</tr>
<tr>
<td>Accretion on Nuclear Waste Obligations and Earnings on Nuclear Segregated Funds – August 12</td>
<td></td>
</tr>
<tr>
<td>Finance – BP&amp;R – Nuclear Waste Management</td>
<td></td>
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<tr>
<td>Pension and OPEB Costs – update by August 16</td>
<td></td>
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<tr>
<td>Finance – BP&amp;R – Actuarial</td>
<td></td>
</tr>
<tr>
<td>Deferral and Variance Accounts – by August 23</td>
<td></td>
</tr>
<tr>
<td>Finance – BP&amp;R – Regulatory Finance</td>
<td></td>
</tr>
<tr>
<td>Asset Service Fees, Accretion on Non-Nuclear Decommissioning Obligations, and Interest Expense</td>
<td></td>
</tr>
<tr>
<td>Finance – BP&amp;PR (for interest, reflecting inputs from Treasury and capitalized interest from BUs)</td>
<td></td>
</tr>
<tr>
<td>Income Taxes and HST Restricted Input Tax Credits (centrally-held cost)</td>
<td></td>
</tr>
<tr>
<td>Finance – Income Tax</td>
<td></td>
</tr>
</tbody>
</table>

### 5.6 Finance Review and Sign-off

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**
- 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

**Contact: Vassa Chase**

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File: 2016-10-26, EB-2016-0152
Exhibit L-1.2-1 Staff-003
Attachment 1, Page 23 of 33
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, 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 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

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)
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.

BU’s 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 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, BU’s 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

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). BU’s 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

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.

CONTACT: KRIS PROBODIAK
6.1.2 Deliverables

The business planning deliverables are detailed in the following schematic:

**Step 1: Identify Risks**
- Confirm BU objectives, related programs and initiatives
- Identify risks to achieving BU objectives, programs and initiatives (consult SMEs as needed)
- Analyze business plan assumptions as a potential source for additional risks

**Step 2: Complete ERM Risk Template**
- Review existing Enterprise and BU risk registers to determine if risks identified in step 1 have already been defined
- For new risks, BU member populates risk template
- BU member submits risk template to BU risk SPOC

**Step 3: Review and Consolidate BU Risks**
- BU risk SPOC reviews and consolidates new and existing BU risks
- BU risk SPOC updates existing risks in Governance, Risk and Compliance (GRC) tool and BU risk registers where applicable and as required

---

1. BUSINESS PLAN PRESENTATION

Business Plans identify the most significant risks impacting BU objectives. These risks are summarized on a separate slide, in the business plan presentation, using the ERM business plan presentation risk template. The summary slide(s) should include a brief description of each risk, an assessment of the residual risk rating and proposed plans for risk treatment.

Responsibility: BU Member / BU Risk SPOC

2. ERM RISK TEMPLATE

The ERM risk template is populated for new risks.

Responsibility: BU Member

3. GRC UPDATE

Existing risks are updated² and new risks are entered into the GRC tool or BU risk registers.

Responsibility: BU Risk SPOC

---

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 Metis 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 Metis 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.

<table>
<thead>
<tr>
<th>Significant Environmental Aspect</th>
<th>Business Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Nuclear</td>
</tr>
<tr>
<td></td>
<td>Operations</td>
</tr>
<tr>
<td>Carbon 14 emissions to air</td>
<td>✓</td>
</tr>
<tr>
<td>Chemical emissions to water</td>
<td>✓</td>
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<tr>
<td>Displacement of fossil fuels</td>
<td>✓</td>
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<tr>
<td>Fish impingement/entainment</td>
<td>✓</td>
</tr>
<tr>
<td>Wildlife habitat (enhancement or disruption)</td>
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<tr>
<td>Spills</td>
<td>✓</td>
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<tr>
<td>Tritium emissions</td>
<td></td>
</tr>
<tr>
<td>Thermal effluent emissions</td>
<td>✓</td>
</tr>
<tr>
<td>Water flows and level changes</td>
<td></td>
</tr>
<tr>
<td>Waste generation: low and intermediate level radioactive waste</td>
<td>✓</td>
</tr>
</tbody>
</table>
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 fulfillment 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

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of 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.
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>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
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<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
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</thead>
<tbody>
<tr>
<td>Headcount</td>
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<td>10,664</td>
<td>10,085</td>
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<td>9,010</td>
</tr>
</tbody>
</table>

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,
identificaiton 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).
<table>
<thead>
<tr>
<th>Title of Study</th>
<th>Study Location</th>
<th>Terms of Reference Location</th>
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</thead>
<tbody>
<tr>
<td>Common Equity Ratio For OPG’s Regulated Generation. Concentric Energy Advisors</td>
<td>Ex. C1-1-1, Attachment 1</td>
<td>Ex. C1-1-1, Attachment 2</td>
</tr>
<tr>
<td>ScottMadden Evaluation of OPG Nuclear Benchmarking. Scott Madden Management Consultants. 2015</td>
<td>Ex. F2-1-1, Attachment 3</td>
<td>Ex. L-1.2-2-AMPCO-1, Attachments 3A and 3B</td>
</tr>
<tr>
<td>Benchmarking Study of OPG’s Corporate Support Functions and Costs. The Hackett Group. April, 2016</td>
<td>Ex. F3-1-1, Attachment 1</td>
<td>Ex. L-1.2-2-AMPCO-1, Attachment 4</td>
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<td>Total Compensation Benchmarking Study. Willis Towers Watson. April 22, 2016</td>
<td>Ex. F4-3-1, Attachment 2</td>
<td>Ex. L-6.6-1-Staff-149, Attachment 1</td>
</tr>
<tr>
<td>Comparison of Salary Schedules for Society and PWU Roles. Willis Towers Watson. April 25, 2016</td>
<td>Ex. F4-3-1, Attachment 3</td>
<td>Ex. L-6.6-1-Staff-149, Attachment 1</td>
</tr>
</tbody>
</table>
# SCHEDULE A – STATEMENT OF WORK

Nuclear Staffing Study

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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.


1.2. Purpose of the Project

For the next three years, 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

<table>
<thead>
<tr>
<th>Name of Candidate</th>
<th>Role</th>
<th>Hourly Rate</th>
<th>Expected Hours of Work</th>
<th>Total Amount</th>
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<tr>
<td>Peter Schneider</td>
<td>Project Manager</td>
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<td>Ed Scholz</td>
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<tr>
<td>Paris Goodnight</td>
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**Effective April 1, 2015 to March 31, 2016**

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

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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.
## Services - Request for Purchasing

**Prepared by:** John Blazanin  
**Title:** Director, Controllership  
**Site/Location:** 880 Brook Road, P82-3  
**Project Title:** Staff Benchmark Study

**Department:** Nuclear Finance  
**Telephone:** (905) 839-6745, ext. 4215

**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:** X  
**Former Employee of OPG:** □

**Has the PSA or CPA been approved?**  
- Yes □  
- No □  
- N/A X

### 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 2006 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.
<table>
<thead>
<tr>
<th>Construction Services / Statement of Work</th>
</tr>
</thead>
<tbody>
<tr>
<td>Include completed N-FORM-11180; 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.</td>
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<td>2015-05-30</td>
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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:
- 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)
- ☐ CSA N286-05 Design (applicable elements)
- ☐ CSA N286.1 (applicable elements)
- ☐ CSA N286.2 (applicable elements)
- ☐ CSA N286.3 (applicable elements)
- ☐ CSA N286.7 Computer Programs

Other

Note: The selection of any of the above CSA N286 programs must be accompanied by a Z399 selection.

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

Other
Services - Request for Purchasing

Section 5: Material Request

Charge to (44 digit code):

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<tr>
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<th>Resource Type</th>
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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

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

Section 6: Required Approvals

Prepared by:

Signature:

Date Submitted:

Location: Tel:

Reviewed by Contract Owner:

Signature:

Date Submitted:

Location: Tel:
## 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.

<table>
<thead>
<tr>
<th>Reviewed by Local Finance:</th>
<th>John Blazanin, Director Controllership, Nuclear Finance</th>
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<td>Signature:</td>
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<td>Date Submitted:</td>
<td>2015-03-03</td>
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<td>Tel:</td>
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I hereby certify the scope and budget are within an approved Project BCS or Business Plan.

<table>
<thead>
<tr>
<th>Approved by the Requisitioning Line Authority as per the OAR:</th>
<th>Glenn Jager, Chief Nuclear Officer</th>
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## Section 7: Exception Approvals
(Refer to OPG-PROC-0058)

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<tr>
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## Section 8: Reviews

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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
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 position 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:
<table>
<thead>
<tr>
<th>(2) Allowable Exceptions for Items and Non-Consulting Services:</th>
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<tr>
<td>□ 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:</td>
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<tr>
<td>□ Where the Procurement is with a public body. Provide further details or justification below:</td>
</tr>
<tr>
<td>□ 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:</td>
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<tr>
<td>□ 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:</td>
</tr>
<tr>
<td>□ 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:</td>
</tr>
<tr>
<td>□ 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:</td>
</tr>
<tr>
<td>□ 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:</td>
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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:

<table>
<thead>
<tr>
<th>Requested By:</th>
<th></th>
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</table>
| Signature:    | [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):  

<table>
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<tr>
<th>Comments:</th>
<th>Approved</th>
<th>Rejected</th>
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<td>Approved pen management instructions</td>
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| Signature: |  |
| Name:      | [Signature] |
| Title:     | Sr. MGA Sr. Sourcing | Date: 3/18/2015 |
### 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

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This document and the information contained herein may be used only in connection with fulfilling the Vendor's obligations to Ontario Power Generation Inc. referred to herein (the "Purpose") and may be provided to any shareholder, director, officer, employee, partner, representative or agent of the Vendor or of any company or other entity associated or affiliated with the Vendor (collectively, the "Representatives") so long as the Vendor ensures such Representatives only use this document and the information contained herein for the Purpose.

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 ****

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<th>Payment Terms</th>
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<td>Reference Contract</td>
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</table>

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-INO-ERS | S Y | PO INVOICING TERMS FOR NON ERS SUPPLIERS ON ARIBA
SUPPLEMNT-1 | V Y | SUPPLEMENTARY TERMS AND CONDITIONS

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<th>Quantity</th>
<th>UP</th>
<th>Item Description</th>
<th>Unit Price</th>
<th>Extension</th>
</tr>
</thead>
</table>
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

USD
TAXABLE

Schedule: 
Quantity: 1
Delivery Date: 31AUG2016

Description: CONSULTING SERVICES

Purchase Order Total Amount

Authorized Signature

Digitally signed by Amir R Mirshahi
DN: c=CA, o=Supply Chain, ou=Strategic Sourcing,
email=amir.mirshahi@oppg.com, c=CA
Date: 2016.08.02 18:31:36 -04'00'

Line Fac Standard Name SUPPLEMENT-1 Variable Terms and Conditions 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
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
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.

Shipment 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.
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/guarantime 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
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
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).  
   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

CPG By: [Signature]

Name: Colin Anderson

Title: Director - Oil Reg Affairs

Date: Nov. 20/15

Hackett By: [Signature]

Name: Anthony Snowball

Title: Practice Leader, Benchmarking

Date: November 23, 2015
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.


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.

Witness Panel: Nuclear Operations and Projects
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.”

Response

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.

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
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).
**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.
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

a. 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.

b. Yes. The PIR for the Niagara Tunnel Project is provided in Attachment 3.

c. On average over 2014 to 2015, OPG’s nuclear business conducted about 20 PIRs per year.
Simplified Post Implementation Review
(For Simplified PIRs only)

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

<table>
<thead>
<tr>
<th>Approval</th>
<th>Cost</th>
<th>Date</th>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original Approval Estimate</td>
<td>$21,680K</td>
<td>Mar 2006</td>
<td>Target Date</td>
</tr>
<tr>
<td>Approval Revision Estimate</td>
<td>$22,872K</td>
<td></td>
<td>Latest Approved i/s Date For all 6 SG's</td>
</tr>
<tr>
<td>Final Approval Estimate</td>
<td>$22,721K</td>
<td>Mar 2007</td>
<td>In Service Date with modification of all 6SG's</td>
</tr>
<tr>
<td>Final Actual Project Cost</td>
<td>$22,751K</td>
<td>Jan 2015</td>
<td>Period used to calculate Performance result</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Target</th>
<th>Achievement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measurable Parameter:</td>
<td>Available for service dates for first 2 SG’s are as below:-</td>
</tr>
<tr>
<td>Available For Service (first 2 SG’s)</td>
<td>1.056-54600-SG3: AFS date 13-Oct-2006</td>
</tr>
<tr>
<td>Targeted Results: AFS and Open Items acceptance by stakeholders</td>
<td>Attachments: i) Copy of AFS report as per N-FORM-10091</td>
</tr>
<tr>
<td>How it will be measured: Attach copy of AFS and Open Items</td>
<td>ii) OPEN items as per AR# 28070181; Current status: Complete</td>
</tr>
<tr>
<td></td>
<td>2.078-54600-SG3: AFS Date 22-Dec-2006</td>
</tr>
<tr>
<td></td>
<td>Attachments: i) Copy of AFS report as per N-FORM-10091</td>
</tr>
<tr>
<td></td>
<td>ii) OPEN items as per AR# 28073103; Current status: Complete</td>
</tr>
<tr>
<td></td>
<td><strong>Note:</strong> - 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:-</td>
</tr>
<tr>
<td></td>
<td>3.056-54600-SG1: AFS date 20-Jul-2007</td>
</tr>
<tr>
<td></td>
<td>4.078-54600-SG1: AFS Date 22-Oct-2007</td>
</tr>
<tr>
<td></td>
<td>5.056-54600-SG2: AFS date 28-Dec-2007</td>
</tr>
<tr>
<td></td>
<td>6.078-54600-SG2: AFS Date 15-Aug-2008</td>
</tr>
<tr>
<td>Measurable Parameter: SG Machine performance criteria met</td>
<td>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:-</td>
</tr>
<tr>
<td>Targeted Results: Commissioning results acceptance by Design</td>
<td>1. NK30-CR-54600-00034: Commissioning report for Standby Generator governor and control upgrade project for 056-54600-SG3 – Cover page attached.</td>
</tr>
<tr>
<td>How it will be measured: Signed commissioning report scanned in Passport</td>
<td>2. NK30-CR-54600-00038: Commissioning report for Standby Generator governor and control upgrade project for 078-54600-SG3 – Cover page attached.</td>
</tr>
<tr>
<td></td>
<td>Commissioning reports for remaining SG’s are as below:-</td>
</tr>
</tbody>
</table>
### 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

<table>
<thead>
<tr>
<th>Measurable Parameter: REGM #28007285 complete</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Measurable Parameter: REGM #28007285 complete</th>
</tr>
</thead>
</table>

### QUALITATIVE RESULTS

<table>
<thead>
<tr>
<th>Health &amp; safety</th>
<th>No health &amp; safety incidents were reported during the project.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower maintenance costs</td>
<td>Governor and logic failures minimized due to installation of upgraded PLC based system and new components.</td>
</tr>
<tr>
<td>Diagnostic capabilities</td>
<td>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.</td>
</tr>
<tr>
<td>Reduction in CM/DM backlogs</td>
<td>Replacement of obsolete system with PLC based system resulted in reduction in CM/DM backlog for governor control components.</td>
</tr>
</tbody>
</table>

### 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”. |

Printed on 15/11/18. This document may have been revised since it was printed. Approved current version posted on the Intranet.
<table>
<thead>
<tr>
<th>Variable Frequency Drive</th>
<th>Variable frequency drive terminal block rating was incorrect for the application. Current status: Replacement terminal blocks installed on all 6 SG's.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annunciator Panel</td>
<td>Frequent annunciator lock up occurred on all SGs resulted in OPS memo. Current Status: New annunciator Panel installed on all 6 SGs</td>
</tr>
<tr>
<td>Vibration cards</td>
<td>Initially installed vibration cards were not suitable for high temperature application for Turbine end. Current Status: Vibration cards replaced for high temp application.</td>
</tr>
</tbody>
</table>

**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: [signature] Date: 18Nov.2015
Naresh Kumar
SE, Standby Generators

Reviewed by: [signature] Date: 21Nov.2015
Dean Townsend
Director- Station Eng

Approved by: [signature] Date: 3Jan.15
Carlo Crozzoli
SVP and Chief Financial officer

Approved by: [signature] Date: 5Jan.15
Jeff Lowish
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
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
Other Reference Number:

Internal Use Only
Commercially Sensitive

Prepared by: B. Barron (Team Lead) Date 29-Mar-2013
Performance Engineering

V. Garcia-Lee – Investment Planning
J. Julian – Performance Engineering
M. Mishra – Design Projects
S. Wong – Investment Planning

Reviewed by: Steve Ramjist Date 30-Apr-2013
Director of Operations and Maintenance
Darlington

Reviewed by: Brian Duncan Date May 1, 2013
Senior Vice President
Darlington

Approved by: Donn Hanbridge Date June 14, 2013
Chief Financial Officer

Approved by: Tom Mitchell Date 13-06-18
President and CEO

Associated with document type REP N-TMP-10010-R010, Controlled Document or Record (Microsoft® 2007)
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FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW

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Preface

Contributions and Acknowledgments

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

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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
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 focused 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:
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 $0.04 M 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.
**FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW**

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

<table>
<thead>
<tr>
<th>Jan-04</th>
<th>FHPT Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sep-04</td>
<td>38451 Project Charter</td>
</tr>
<tr>
<td></td>
<td>* project scope: (a) system analysis work, (b) 9 FH PT modifications (mods) &amp; (c) FH PT mctc</td>
</tr>
<tr>
<td>Nov-04</td>
<td>NSS Risk Assessment completed</td>
</tr>
<tr>
<td>Mar-06</td>
<td>38451 BCS - Project Full release</td>
</tr>
</tbody>
</table>

---

### Capital Improv. Project 31438

| Apr-06 | 31438 Project Charter |
| May-07 | 31438 BCS - Developmental release |
| Nov-07 | 31438 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 |
| Jul-10 | 31438 BCS - Full release Phase 2 |
| Nov-11 | 31438 Report of Equip. In-service |
| Nov-12 | 31438 Project Closure |

### OM&A Improv. Project 38472

| Apr-06 | 38472 Project Charter |
| May-07 | 38472 BCS - Developmental release |
| Nov-07 | 38472 BCS - Partial release |
| May-10 | 38472 BCS - Full release |
| Oct-12 | 38472 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>
<thead>
<tr>
<th>Date</th>
<th>Type</th>
<th>Amount</th>
<th>Scope</th>
<th>Estimated Cost</th>
<th>Full Scope</th>
</tr>
</thead>
<tbody>
<tr>
<td>May-07</td>
<td>Developmental</td>
<td>$1.4M</td>
<td>• preliminary engineering for DRD &amp; DI</td>
<td>$10.943M listing estimate (+100% to -50%): VSS, DRD, DI</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• pursue alternatives for VSS design</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov-07</td>
<td>Partial</td>
<td>$4.4M</td>
<td>• scope: complete design of DI, DRD &amp; VSS PMODS</td>
<td>$9.3M [conceptual estimate (+60% to -25%): VSS, DRD, DI</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• prepare for installn (2009 VBO)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan-09</td>
<td>Full release</td>
<td>$8.5M</td>
<td>• install VSS release (rel) 2 during VBO; design/install VSS rel 3 &amp; 4; commission VSS [AFS Sept 2010]</td>
<td>$17.4M [release quality estimate +15%/-10%]: VSS, DI, pilot DRD</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Phase 1</td>
<td></td>
<td>• procure/ install/ commission DI [AFS July 2011]</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• install DRD pilot with full implementn in next release</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• train Ops&amp;Mtce &amp; Perf Eng staff</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• revise Ops Mtce procedures</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• ECC closeout for DI &amp; VSS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jul-10</td>
<td>Full release</td>
<td>$1.8M</td>
<td>• VSS going ahead; DRD and DI cancelled</td>
<td>$16.2M [release quality estimate +15%/-10%]: VSS</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Phase 2</td>
<td></td>
<td>- previous release: Design of VSS rel 1, 2 &amp;3; matl purchase &amp; install of VSS rel 1&amp;2</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- this release: design VSS rel 4; matl purchase &amp; install of VSS rel 3 &amp;4; commission VSS</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• project closeout</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov-12</td>
<td>Project Closure</td>
<td></td>
<td>• final cost : $16.1M</td>
<td></td>
<td>VSS</td>
</tr>
</tbody>
</table>
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 % contingency
- $9.3 M in November 2007 (partial release) including % contingency
- $17.4 M in January 2009 (full release phase 1) including % 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 than 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 pursuing 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).
**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.
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

<table>
<thead>
<tr>
<th>Cost Stream</th>
<th>Actual $k</th>
<th>Approved $k</th>
<th>Variance $k</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Management &amp; Support</td>
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<td></td>
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</tr>
<tr>
<td>Engineering</td>
<td></td>
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<tr>
<td>Procurement</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Contingency</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>16,120</td>
<td>16,156</td>
<td>(36)</td>
<td>0.2</td>
</tr>
</tbody>
</table>

#### 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)

<table>
<thead>
<tr>
<th>PCRAF</th>
<th>Approval Date</th>
<th>Description of Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>001</td>
<td>Jun 19, 2008</td>
<td>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</td>
</tr>
</tbody>
</table>
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>
<thead>
<tr>
<th>BCS</th>
<th>Release Capital ($k)</th>
<th>Estimated Final Costs ($k)</th>
<th>Scope</th>
</tr>
</thead>
<tbody>
<tr>
<td>Developmental</td>
<td>1,383</td>
<td>10,943</td>
<td>DI, DRD, VSS</td>
</tr>
<tr>
<td>Partial</td>
<td>4,417</td>
<td>9,285</td>
<td>DI, DRD, VSS</td>
</tr>
<tr>
<td>Full Phase 1</td>
<td>8,530</td>
<td>17,258</td>
<td>DI, DRD, VSS</td>
</tr>
<tr>
<td>Full Phase 2</td>
<td>1,826</td>
<td>16,156</td>
<td>VSS</td>
</tr>
</tbody>
</table>
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:

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 brainstorming, 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.
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 as 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:
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

<table>
<thead>
<tr>
<th>Project</th>
<th>Time</th>
<th>DI</th>
<th>DRD</th>
<th>VSS</th>
</tr>
</thead>
<tbody>
<tr>
<td>16-38451</td>
<td>2004-2006</td>
<td>DP</td>
<td>DP</td>
<td>DP</td>
</tr>
<tr>
<td></td>
<td>Dev BCS (May 2007)</td>
<td>DP</td>
<td>DP</td>
<td>DP</td>
</tr>
<tr>
<td>16-31438</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Partial BCS  (Nov 2007)</td>
<td>DP</td>
<td>DP</td>
<td>FH</td>
</tr>
<tr>
<td></td>
<td>Phase 1 BCS (Jan 2009)</td>
<td>DP</td>
<td>DP</td>
<td>FH</td>
</tr>
<tr>
<td></td>
<td>Full BCS (Jul 2010)</td>
<td>-</td>
<td>-</td>
<td>DP</td>
</tr>
</tbody>
</table>

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>
<thead>
<tr>
<th>Master EC</th>
<th>Design ECs</th>
<th>Description</th>
<th>AFS Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>96905</td>
<td>98730, 98518, 98519</td>
<td>Release 1</td>
<td>2011-11-30</td>
</tr>
<tr>
<td>96905</td>
<td>98520, 98521</td>
<td>Release 2</td>
<td>2011-11-30</td>
</tr>
<tr>
<td>96905</td>
<td>101353, 101352</td>
<td>Release 3</td>
<td>2011-11-30</td>
</tr>
<tr>
<td>96905</td>
<td>103382, 103383</td>
<td>Release 4</td>
<td>2011-11-30</td>
</tr>
</tbody>
</table>
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 $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 measureable 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>
<thead>
<tr>
<th>Parameter</th>
<th>Baseline</th>
<th>Target Result</th>
<th>How measured &amp; by Whom?</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. avoid derating thru improved PT surveillance</td>
<td>1. Temp &amp; non-repairable PT VSS is failing &amp; does not cover entire PT</td>
<td>1. provide permanent &amp; maintainable VSS with 90% increase in surveillance area resulting in improved FM availability</td>
<td>1. % visibility coverage of PT during normal ops with VSS alone; reduced operator dose [measured by FH-Technical (SRE)]</td>
</tr>
<tr>
<td>2. avoid derating thru improved PT surveillance</td>
<td>2. VSS failing which reqs deviation request for Ops procedures</td>
<td>2. uninterrupted surveillance of fuelling operations</td>
<td>2. camera availability [measured by FH-Technical (SRE)]</td>
</tr>
<tr>
<td>3. avoid derating thru improved PT surveillance</td>
<td>3. FFAA bay camera does not cover reqd view of manual ops in ancilliary ports</td>
<td>3. 90% increase in surveillance coverage of manual operations in FFAA ancillary ports</td>
<td>3. % of visibility coverage of ancillary ports [measured by FH-Technical (SRE)]</td>
</tr>
<tr>
<td>4. project executed within approved budget &amp; schedule</td>
<td>not applicable</td>
<td>4. key milestones met and project cost within approved release</td>
<td>4. CPI; SPI; milestone adherence [MFL, Design projects to measure]</td>
</tr>
</tbody>
</table>

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 is shown below:

### Table 5.2: Camera Coverage Areas in Design Manual

<table>
<thead>
<tr>
<th>Section</th>
<th>Coverage Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.2.1.1 Fuelling Machine and Transport Trolley</td>
<td>1. Snout locking mechanism during homing and locking in reactor channel or FFAA ports.</td>
</tr>
<tr>
<td></td>
<td>2. Catenaries during fueling machine transversing</td>
</tr>
<tr>
<td></td>
<td>3. Trolley mounted auxiliaries, gauges, counters etc</td>
</tr>
<tr>
<td></td>
<td>4. Reactor Area Bridge Drive.</td>
</tr>
<tr>
<td></td>
<td>5. Reactor face</td>
</tr>
<tr>
<td></td>
<td>6. Indicator of TMM Magazine position providing information on what type of component is being installed in each position (only during outage TMM use)</td>
</tr>
<tr>
<td></td>
<td>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)</td>
</tr>
<tr>
<td></td>
<td>8. Cover entire Trolley area by a hand held camera connecting to the CCTV system to be viewed remotely from MCR.</td>
</tr>
<tr>
<td>2.2.1.2 Central Service Area</td>
<td>1. End drum, end drum wheel assembly and end drum support assembly</td>
</tr>
<tr>
<td></td>
<td>2. Intermediate roller, end plate assembly, endplate wheel assembly and pillow block bearing surface.</td>
</tr>
<tr>
<td></td>
<td>3. Inner side of C channel for any debris, grooved wheel round bar and flat wheel bar.</td>
</tr>
<tr>
<td></td>
<td>4. Chain sag, outside side chain pins, carrier bar, outside carrier bar pins, cable, cable riser and coupling frame.</td>
</tr>
<tr>
<td>2.2.1.3 East and West Reception Bay</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>2. Camera shall provide view of reception bay Irradiated Fuel Discharge Mechanism (IFDM).</td>
</tr>
<tr>
<td>2.2.1.4 Wet Flask Handling Area</td>
<td>1. A camera shall be provided in the wet flask handling area for viewing irradiated fuel flask handling and shipping operation.</td>
</tr>
</tbody>
</table>
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.
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

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Assessed Corrective / Deficient Hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>123</td>
</tr>
<tr>
<td>2012</td>
<td>324</td>
</tr>
<tr>
<td>2011</td>
<td>580</td>
</tr>
<tr>
<td>2010</td>
<td>48</td>
</tr>
<tr>
<td>2009</td>
<td>20</td>
</tr>
<tr>
<td>2008</td>
<td>16</td>
</tr>
<tr>
<td>2007</td>
<td>22</td>
</tr>
</tbody>
</table>
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>
<thead>
<tr>
<th>WO / WR</th>
<th>Deficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>W/R 869100 (W/O 2861819)</td>
<td>Poor image quality on T(3 and T(4 trolley cameras (VC 3 and VC4) .</td>
</tr>
<tr>
<td>W/O 2694182</td>
<td>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.</td>
</tr>
<tr>
<td>W/O 2825316</td>
<td>Cameras VC 26 and VC 29 were replaced during the D1231 outage but still do not function. Control maintenance to perform troubleshooting activities.</td>
</tr>
<tr>
<td>W/O 2745944</td>
<td>Trolley 2 camera (VC2) found to be defective. Control maintenance has replaced the defective camera, and has rebuilt the defective camera.</td>
</tr>
<tr>
<td>W/O 2805413</td>
<td>Trolley 6 camera (VC6) has no signal in the main control room. Control</td>
</tr>
</tbody>
</table>
maintenance has swapped the camera on Trolley 6 with a working unit on Trolley 5, with no results. Cable troubleshooting work is still outstanding.

<table>
<thead>
<tr>
<th>Work Order</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>W/R 869102 (W/O 2501272, 2863785)</td>
<td>Trolley 5/6 power track camera has been knocked off its mounting. New brackets need to be installed.</td>
</tr>
</tbody>
</table>

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:
FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW

- 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

<table>
<thead>
<tr>
<th>LL Ref.</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>LL 3.2.1</td>
<td>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.</td>
</tr>
<tr>
<td>LL 3.2.2</td>
<td>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.</td>
</tr>
<tr>
<td>LL 3.4.1</td>
<td>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.</td>
</tr>
<tr>
<td>LL 3.4.2</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.1.1</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.1.2</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.2.1</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.2.2</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.2.3</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.3.1</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.3.2</td>
<td>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.</td>
</tr>
<tr>
<td>LL 4.3.3</td>
<td>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...</td>
</tr>
</tbody>
</table>
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
### 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
DNSG  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
O&M&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


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[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-12] "Fuel Handling Power Track Cameras Lessons Learned", D-LLD-60260-10001, 2013-Jan-16


Title:
FUEL HANDLING POWER TRACK CAPITAL IMPROVEMENT PROJECT (16-31438) - COMPREHENSIVE POST IMPLEMENTATION REVIEW

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

<table>
<thead>
<tr>
<th>Name</th>
<th>Title</th>
<th>Department</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bill Barron</td>
<td>Senior Technical Engineer</td>
<td>DN Performance Engineering</td>
</tr>
<tr>
<td>Justin Julian</td>
<td>Senior Technical Engineer</td>
<td>DN Performance Engineering</td>
</tr>
<tr>
<td>Mukesh Mishra</td>
<td>Senior Technical Engineer</td>
<td>DN Design Projects</td>
</tr>
<tr>
<td>Silvester Wong</td>
<td>Senior Planning Engineer/Financial Analyst</td>
<td>Asset Planning &amp; Integration</td>
</tr>
<tr>
<td>Violeta Garcia-Lee</td>
<td>Senior Planning Engineer/Financial Analyst</td>
<td>Asset Planning &amp; Integration</td>
</tr>
</tbody>
</table>

A.7.0 REFERENCE DOCUMENTS

The CPIR report will base its conclusions and recommendations on the following documents:
### 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.

<table>
<thead>
<tr>
<th>Description</th>
<th>Accountability/Lead</th>
<th>Target Completion Date</th>
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<tr>
<td>1. Prepare draft Terms of Reference (TOR), scope of work and schedule, identify team</td>
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<td>2. CPIR Workshop</td>
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<td>08-Jan-2013</td>
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<td>3. Review and confirm TOR with Team Members / 1st Team familiarization meeting; Finalize TOR</td>
<td>Team Leader</td>
<td>14-Jan-2013</td>
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<tr>
<td>4. Project Documentation Review</td>
<td>Team</td>
<td>25-Jan-2013</td>
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<tr>
<td>5. Conduct Interview Sessions with Stakeholders</td>
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<td>08-Feb-2013</td>
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<tr>
<td>6. Analysis and Draft Report Compilation</td>
<td>Team</td>
<td>01-Mar-2013</td>
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<td>7. Draft report - Review with Key Stakeholders</td>
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<td>8. Finalize and Submit Final Report to Project Approval Authority</td>
<td>Team Leader</td>
<td>30-Mar-2013</td>
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</tbody>
</table>

Additional documents may be added to this list as the CPIR document review and interview process takes place.
A.9.0 SIGNATURES

Prepared By: 
Bill Barron – CPIR Team Leader
Date: 14-Jan-2013

Reviewed by: 
Fred Mason – Section Manager
Darlington Fuel Handling Engineering
Date: 14-Jun-2013

Approved by: 
Steve Ramjist – Project Sponsor
Director - Operations & Maintenance
Darlington
Date: Jan 14, 2013
### Appendix B: AFS Outstanding Action Tracking Items

<table>
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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
Niagara Tunnel Project
Post Implementation Review

Prepared by:

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Canadian Power Utility Services
Date: Nov 30, 2016

Reviewed by:

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Project Manager, Project Execution - RGPM
Date: Dec 2, 2016

Approved by:

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Date: Dec 10, 2016

K. Hartwick
Senior Vice President Finance, Strategy, Risk & Chief Financial Officer
Date: Dec 5, 2016

A. Lyash
President and Chief Executive Officer
Date: Dec 7, 2016
Niagara Tunnel Project

Post-Implementation Review
Niagara Tunnel Project
Post Implementation Review

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Approved by:

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Date:

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J. Lyash
President and Chief Executive Officer
Date:
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Executive Summary

The Niagara Tunnel Project was intended to take advantage of additional water available from the Niagara River under the Niagara Diversion Treaty, thereby increasing the annual energy output of the Sir Adam Beck (SAB) generating complex by up to 1.6 TWh per year. When the OPG Board of Directors approved it in July 2005, the new tunnel was expected to be in-service by June 2010, and the cost was estimated to be $985 million.

Substantial geotechnical investigations to establish the subsurface conditions along the tunnel route had been carried out over several years prior to the Project. Nevertheless, unexpectedly difficult rock conditions were encountered within the Queenston Shale layer during the first year of tunnel mining. This resulted in a significant delay and Contractor claims for additional costs that required revision of the Project schedule and budget and approval of a Superseding Business Case by the OPG Board in 2009. Under an amended agreement with the Contractor, a new target cost and target schedule were established that set the approved tunnel in-service date as December 2013 and the revised Project budget, including contingency, at $1,600 million. The tunnel was completed and put in service in March 2013 and the final Project cost is now expected to be approximately $1,464 million.

The completed tunnel is 10.2 km long with a finished internal diameter of 12.7 m. It reaches a maximum depth below the surface of 140 m. The facility also includes a new intake and modifications to the existing International Niagara Control Works upstream of Niagara Falls, and an outlet with an emergency closure gate at the SAB end. The tunnel discharges into the Pumping Generating Station Canal near the PGS reservoir. The new tunnel has met its key business objective of delivering 500 m$^3$/s of additional flow to the SAB Complex.

The Project was carried out using a Design-Build approach, with Strabag AG of Austria being the prime Contractor. A Tunnel Boring Machine manufactured by the Robbins Company under subcontract to Strabag was used to excavate the tunnel. Hatch Mott MacDonald acted as OPG’s Owner’s Representative throughout the Project.

6.79 million labour hours were worked on site over the eight years of construction. A total of 735 days were reported lost due to work-related injuries or illnesses for an overall LTI frequency of 0.94. This was below the Ontario construction industry average over that period. In addition, all Environmental Assessment and Community Impact Agreement commitments for the Project were met.
1 Introduction

The Sir Adam Beck (SAB) hydroelectric complex at Niagara consists of two generating stations (SAB1 and SAB2), with a total generating capacity of 1,960 MW, and a Pumped Generating Station (PGS) with a capacity of 174 MW. The PGS is used to pump and store water during off-peak periods for use during periods of peak electricity demand.

Water for SAB1 originally came from the Chippawa-Queenston Power Canal, built in the 1920s. In the early 1950s, two underground tunnels were built to provide water for SAB2. The recent Niagara Tunnel Project (NTP or Project) was undertaken to construct a new diversion tunnel to convey approximately 500 m$^3$/s of water from the upper Niagara River to the SAB complex. This flow would allow the SAB complex to generate an additional 1.6 TWh$^1$ per year of energy, an increase of 14% above the then current 12 TWh.

A Tunnel Boring Machine (TBM) was used to create a 10.2 km long tunnel with a finished internal diameter of 12.7 m. The tunnel reaches a maximum depth below the surface of 140 m. The Project also included a new intake along with modifications to the existing International Niagara Control Works (INCW), an outlet with an emergency closure gate near the PGS reservoir, and removal of the PGS canal dewatering structure.

The Project was approved for execution on July 28, 2005. The originally approved in-service date of the tunnel was June 2010 and the estimated total cost of the Project at release was $985 million.

The contract for construction of the tunnel and associated works was awarded to Strabag AG of Austria in August of 2005 and work at the outlet site began in September 2005. After delivery and assembly of the TBM, tunnel mining started in September 2006. Due to delays caused by unexpectedly difficult rock conditions, mining of the tunnel was not completed until March 2011. Construction of the tunnel liner started in December 2008 and liner grouting – the last stage of tunnel construction – was completed in February 2013. After removal of the cofferdam at the intake, and the rock plug at the outlet, the tunnel was watered up and placed in service in March 2013. Testing showed that the tunnel has achieved the guaranteed flow rate. The final Project cost will be approximately $1.464 billion.

The Project was selected as the “North American Project of the Year for 2013” by International Water Power & Dam Construction magazine, and in November 2013 the Project was also named “Canadian Project of the Year” by the Tunnelling Association of Canada. The Project also received a “2014 Award of Excellence” from

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$^1$ This estimate of additional energy was subsequently reduced to 1.5 TWh.
the Association of Consulting Engineering Companies Canada and a “2015 Grand Award” from the American Council of Engineering Companies.

The cost and duration of this Project required that a Comprehensive Post Implementation Review (PIR) be carried out in accordance with OPG Procedure FIN-PROC-0056. A Comprehensive PIR is an independent review of a completed project conducted in order to:

- 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 investment objectives stated in the Business Case Summary 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 PIR Plan included in the original (2005) Business Case supporting approval of the NTP established parameters, targets and measures for assessing the Project outcomes. A Superseding Business Case (SBCS) approved in 2009 reset the targets for these outcomes, as shown below:

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<th>Parameter</th>
<th>2005 BCS Target</th>
<th>2009 SBCS Target</th>
<th>Measure</th>
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<tr>
<td>Tunnel capacity</td>
<td>500 m$^3$/s</td>
<td>500 m$^3$/s</td>
<td>Flow test$^2$</td>
</tr>
<tr>
<td>In-service date (Including contingency)</td>
<td>June 2010</td>
<td>December 2013</td>
<td>Contract substantial completion date (with approved changes)</td>
</tr>
<tr>
<td>Cost</td>
<td>$985 million</td>
<td>$1,600 million</td>
<td>Actual cost compared to approved release</td>
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This PIR report compares the actual Project outcomes against the original and subsequently modified and approved targets, and also discusses elements of the project management and risk management processes that affected these outcomes. A very comprehensive history of the NTP has been documented in evidence supplied for the

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$^2$ Test was to be done by the Design/Build Contractor with oversight by an independent Chief of Test.
Ontario Energy Board (OEB) rate hearings\(^3\), and therefore only significant and relevant highlights of that history will be repeated in this report.

It should be noted that the overall Project release also included a $43.9 million associated project to make modifications to the retired Ontario Power and Toronto Power Generating Stations, both owned at the time by OPG, as part of a 2005 agreement for transfer of these stations to the Niagara Parks Commission (NPC). This project, which was managed directly by OPG in parallel with the NTP, and completed in July 2007, is not part of the scope of this PIR except as it relates to the overall Project cost.

The PIR findings in this report were based primarily on a review of Project documents, such as the Charter, Business Case(s), Project Execution Plan, risk documentation, monthly reports, event logs, etc. Where necessary for clarification, interviews with selected Project participants provided additional information. An extensive electronic Project document repository was very helpful in conducting this PIR.

Throughout this report where the term “Contractor” is used, it may include Strabag, the prime contractor, as well as Strabag’s subcontractors. The current Niagara Operations group was known as the Niagara Plant Group (NPG) during most of the Tunnel Project, and the latter title is used within this report.

2 Project Origin

The Niagara Diversion Treaty of 1950 defines the minimum seasonal Niagara River volumes\(^4\) that must be allowed to flow over Niagara Falls to preserve its value as a scenic attraction. Any flow in excess of these minimums is available equally between the United States and Canada for diversion for hydroelectric power production. OPG has the exclusive right to use the Canadian share of the diversion flow. This share ranges from about 600 to 3,000 m\(^3\)/s, and averages about 2,000 m\(^3\)/s. This available flow is greater than the 1,800 m\(^3\)/s capacity of the original SAB diversion facilities (canal and two tunnels) about 65 per cent of the time. By constructing new facilities to increase the diversion capacity to about 2,300 m\(^3\)/s the available flow would exceed OPG’s diversion capacity only about 15 per cent of the time.

Feasibility studies for an expansion of Ontario Hydro’s hydroelectric facilities at Niagara, to use more of the available flow, had started in 1982. Definition Phase engineering and environmental assessment work for the “Niagara River Hydroelectric Development” started in 1988. At the time, the proposed new development would have included two new tunnels and a new underground powerhouse (SAB3) at the SAB complex. An

\(^3\) OECB Case_EB-2013-0321 “Capital Expenditures – Niagara Tunnel Project”, Exhibit D1, Tab 2, Schedule 1 September 27, 2013

\(^4\) The Niagara Diversion Treaty requires that 100,000 cfs (2,832 m\(^3\)/s) be allowed to flow over the Falls from 8:00 am until 10:00 pm between April 1 and September 15, and from 8:00 am until 8:00 pm between September 16 and October 31. At all other times the allowable flow is 50,000 cfs (1,416 m\(^3\)/s).
Environmental Assessment (EA) for the proposed project was submitted in March 1991 but work on the project was suspended in 1993 during a major corporate reorganization. Nevertheless, the EA approval was obtained in October 1998. In the meantime, Ontario Hydro had written off the Definition Phase expenditures of $57 million.

The EA approval gave Ontario Hydro the flexibility to undertake the development in phases. In February 1998, a decision was made to proceed with the construction of only one tunnel. Tenders were called for detailed design and construction, and a preferred bidder was selected. However, work was again suspended indefinitely in June 1999 due to another reorganization and corporate funding constraints related to the decision to proceed with the Pickering A Restart. A Project Closeout Report was prepared to document the procurement process to that point, and to identify actions to be taken in the event the project was restarted. Expenditures in 1998-99 totalled $2.5 million and were also written off.

In November 2002, the Provincial Government announced that it would ask OPG to proceed with a new tunnel at Niagara; however, no formal direction to do so was given at the time. Subsequently, the new Government elected in 2003 stated that it wished the project to proceed as soon as possible. In early 2004, the Provincial Government also indicated that the SAB complex, including the new tunnel, would be included as part of OPG’s rate regulated base load hydroelectric generation. Under this condition, all “prudently incurred costs” for the tunnel would be recoverable\(^5\).

An agreement between the NPC and OPG, dated February 18, 2005, committed OPG to complete remedial work at the retired Ontario Power and Toronto Power generating stations, both owned by OPG, as part of reversion\(^6\) of these stations to the NPC which planned to use them as a visitor attraction. In exchange for these stations, the NPC would grant exclusive Canadian Niagara River water rights to OPG until 2056. An associated $10 million settlement with Fortis Ontario, approved by the OPG Board on February 8, 2005, secured an irrevocable assignment of the water associated with Fortis’ Rankine GS\(^7\).

One additional consideration at the time, influencing the timing of the tunnel project, was the expected need to take the existing 83-year old SAB1 power canal out of service for up to a year to allow remedial work to be done. Because this canal delivered about one third of the water needed for the SAB Complex, this would have led to a generation

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\(^5\) This was subsequently formalized under Ontario Regulation 53/05, effective April 1, 2005.

\(^6\) The reversion subproject was managed by OPG and completed in August 2007 at a total cost of $39.7 million. Construction work was carried out by Peter Kiewit and Sons, with Owner’s Representative services by Klohn Crippen and MWH.

\(^7\) Fortis was the owner of Canadian Niagara Power which had an agreement with NPC, dating from 1892, for Niagara River water rights for the Rankine Generating Station. The franchise agreement was due to expire on April 30, 2009 when the Rankine station would revert to the NPC. The (Canadian) water rights associated with the franchise agreement represented approximately 283 m\(^3\)/s of Niagara River flow.
loss of between 2.7 and 4.0 TWh. Completion of the new tunnel prior to this remedial work, scheduled for 2011, would reduce the generation loss. However, as of the date of this report, this work has been deferred until 2021.

On June 24, 2004, the OPG Board of Directors approved a partial release of $10 million to restart Definition Phase planning work and to conduct a Request for Proposal process for a single tunnel project. At that time, the estimated cost of the project, based on escalation of the lowest bid price received in 1998, was approximately $600 million. A Project Charter, authorizing the Definition Phase, was approved in January 2005. After completion of the RFP and contractor selection process, as well as other pre-project planning activities, the Business Case Summary along with supporting information requesting OPG Board of Directors approval of the Project, designated as EXEC-0007, was submitted and approved in July 2005.

3 Project Approval

3.1 Business Objective
The Business Case Summary for OPG Board approval in 2005 stated that the overall Project objective was to:

“Design, construct and commission a new water diversion tunnel to convey 500 m³/s of water from the upper Niagara River to the Sir Adam Beck GS complex at Queenston, to capture a unique, site-specific opportunity for OPG to produce additional, low-cost, renewable and environmentally sustainable energy for its customers, enhancing the existing hydroelectric facilities in the efficient use of Niagara River flow available to Canada for power generation.”

The recommendation approved by the Board also established as objectives for the Project that it be completed at a total cost of $985 million, including $22.5 million previously approved for project development, and that it be placed in service by June 2010.

3.2 Alternatives
The Business Case considered by the Board presented two alternatives:

Base Case – Do Nothing
The Do Nothing option would have foregone the opportunity for OPG to increase its use of the Niagara River water available to Canada for power generation and thereby increase average annual energy output from the SAB generating stations. Also, remedial work at the retired Ontario Power and Toronto Power generating stations, would still have been required to meet OPG’s commitments under the Niagara Exchange Agreement for the reversion of these stations to the NPC. A write-off of about
$37 million would have been taken to cover project development expenditures committed to date ($22.5 million) and the forecast remaining costs associated with the reversion agreement work. This alternative would also have resulted in a temporary generation loss of between 2.7 and 4 TWh while the canal was taken out of service for the remedial work planned at the time.

**Alternative 1 - Design & Construct a Diversion Tunnel (Preferred Alternative)**
The preferred and recommended alternative was to design, construct and commission the new diversion tunnel to convey approximately 500 m$^3$/s to the SAB Complex. This alternative would be done through a design-build contracting approach, intended to minimize the risk to OPG and “achieve price and schedule certainty”.

### 3.3 Financial Analysis
Since the Niagara Tunnel was expected to be part of OPG’s regulated hydroelectric assets and receive a regulated rate, including cost recovery and a return on capital, financial metrics other than NPV and/or ROI were used in evaluating the economics of the investment relative to other generation options. These metrics were:

- **Levelized Unit Energy Cost (LUEC)** - representing the price required to cover all forecast costs, including a return on capital over the service life, escalated over time at the rate of inflation. LUEC permits a consistent cost comparison between generation options with different service lives and cost flow characteristics.

- **Equivalent Power Purchase Agreement (PPA) Price** - representing the price required if the Project had been bid into the RFP$^8$ for renewable energy. EPPA was similar to LUEC except only 15% of the PPA was escalated at the Consumer Price Index.

- **Revenue Requirement** - a measure representing the annual accounting cost of this Project including an allowed return on capital employed. Revenue Requirement generally declines over time as the rate base is depreciated.

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$^8$ In 2004 and 2005, the Ontario Ministry of Energy had issued three requests for proposals (RES I, RES II and RES III) to acquire approximately 1300 MW of renewable energy supply capacity.
These metrics all reflected full recovery of costs, including a return on the investment. The analysis results were as follows:

<table>
<thead>
<tr>
<th>Financial Measure</th>
<th>Base Case</th>
<th>Preferred Alternative</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial or remaining costs ($ million)</td>
<td>14</td>
<td>963</td>
</tr>
<tr>
<td>LUEC (¢/kWh in 2005$)</td>
<td></td>
<td>4.8</td>
</tr>
<tr>
<td>Equivalent PPA Price (¢/kWh in 2011$)</td>
<td></td>
<td>6.7</td>
</tr>
<tr>
<td>Revenue Requirement (¢/kWh in 2011$)</td>
<td></td>
<td>5.8</td>
</tr>
<tr>
<td>Revenue Requirement for OPG Baseload Hydroelectric (¢/kWh in 2011$) including 10% return on equity</td>
<td>3.8</td>
<td>3.9</td>
</tr>
</tbody>
</table>

The estimated equivalent PPA Price of 6.7 ¢/kWh (2011$) was less than the estimated average PPA Price of 8.0 ¢/kWh (2011$) for the successful proponents in response to the RFP that had recently been issued by the Province for renewable electricity supply alternatives.

The financial analysis concluded that completion of the Project would result in a significant increase in average annual energy output from the SAB complex with only a marginal increase in the estimated required regulated rate for OPG’s hydroelectric assets.

Also as part of the Business Case, a sensitivity analysis was done to examine the impact of several factors on the Project economics, as shown below:
Table 3.2

<table>
<thead>
<tr>
<th>Sensitivity Analysis (June 2010 In-Service Date)</th>
<th>Incremental Energy TWh</th>
<th>LUEC (¢/kWh in 2005$)</th>
<th>Equivalent PPA Price (¢/kWh in 2011$)</th>
<th>Revenue Requirement (¢/kWh in 2011$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preferred Alternative</td>
<td>1.6</td>
<td>4.8</td>
<td>6.7</td>
<td>5.8</td>
</tr>
<tr>
<td>Water availability</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Lower quartile for first 5 years of service</td>
<td>0.7</td>
<td>5.4</td>
<td>8.1</td>
<td>n/a</td>
</tr>
<tr>
<td>- Upper quartile for first 5 years of service</td>
<td>2.4</td>
<td>4.2</td>
<td>5.5</td>
<td>n/a</td>
</tr>
<tr>
<td>- Overall reduction of 5% in Niagara River Flow</td>
<td>1.2</td>
<td>6.4</td>
<td>9.3</td>
<td>n/a</td>
</tr>
<tr>
<td>Higher cost (+10%)</td>
<td>1.6</td>
<td>5.2</td>
<td>7.4</td>
<td>6.3</td>
</tr>
<tr>
<td>Shorter (30 year) Service Life</td>
<td>1.6</td>
<td>5.8</td>
<td>7.6</td>
<td>7.1</td>
</tr>
<tr>
<td>Elimination of 10 Year Gross Revenue Charge Holiday</td>
<td>1.6</td>
<td>5.8</td>
<td>8.5</td>
<td>9.1</td>
</tr>
<tr>
<td>Other Renewable Supply</td>
<td></td>
<td></td>
<td></td>
<td>8</td>
</tr>
</tbody>
</table>

3.4 Risks

Given the expected cost and duration of the NTP, as well as problems that had been encountered with the Pickering A Restart Project, it was known that risk management would be a key concern of the OPG Board of Directors when considering the Project for approval. Therefore qualitative and quantitative risk assessments, as described in Section 4.7, were done with the assistance of an external consultant, prior to submission of the Business Case for approval.

3.4.1 Qualitative Risk Assessment

The Business Case Summary listed 20 risks that had been identified through the pre-release stages of the risk management process. The qualitative risk assessment process sorted the risks into those having an expected high, medium or low impact on the Project objectives. The following table lists the risks with a “high” (before mitigation) rating as of the date of Project release, and shows the mitigation actions planned or already completed to reduce the probability or consequence of the risk occurring:

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9 Risk probabilities, and impacts on each objective, were given ratings of 1 (low) to 5 (high). The product of the risk probability and highest risk impact determined the risk level.
### Table 3.3

<table>
<thead>
<tr>
<th>Risk</th>
<th>Consequence</th>
<th>Rating Before Mitigation</th>
<th>Mitigation</th>
<th>Rating After Mitigation</th>
</tr>
</thead>
</table>
| The Contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR) | Unexpected, adverse subsurface conditions could slow tunnel construction and require the Contractor to undertake remedial/extra work resulting in legitimate claims for extra costs and/or schedule extension for differing subsurface conditions (DSC). | High                     | • The GBR is based on extensive field investigations carried out over a 10-year period and knowledge gained through construction of the existing SAB2 tunnels.  
• The 3-stage GBR process used facilitates contractor input and concurrence before construction begins.  
• Residual tunnel construction risk to OPG is addressed by a contingency allowance of $96 million in the Project release estimate and a contingency allowance of 8 months in the scheduled in-service date, both based on a 90% confidence level. | Medium                   |
| OPG resources with knowledge and experience required for design and construction of a major tunnel are severely limited. | OPG resource limitations could have significant impacts on Project quality, cost and schedule. | High                     | • OPG has engaged Hatch Mott MacDonald, an Ontario based consultant with considerable tunnel design and construction management experience, as Owner’s Representative for this Project.  
• The design/build contracting approach, engaging internationally experienced tunnelling experts, will provide the necessary engineering and construction expertise. | Low                      |
<p>| Queenston Shale, the host rock formation for the majority of the tunnel, has swelling properties when exposed to fresh water. | Swelling of the Queenston Shale surrounding the tunnel could over-stress the tunnel lining and cause damage that would interrupt flow through the tunnel and require expensive remedial work. | High                     | • Because this kind of damage could take decades to develop, penalties, warranties or holdbacks are impractical. Instead this risk is being mitigated through conservative, mandatory engineering specifications for aspects of the tunnel design related to rock swelling. | Low                      |
| Design/Performance                                                   | The constructed tunnel may not meet design/performance                        | High                     | • Mandatory design requirements established                                                                                                                                                             | Low                      |</p>
<table>
<thead>
<tr>
<th>Risk</th>
<th>Consequence</th>
<th>Rating Before Mitigation</th>
<th>Mitigation</th>
<th>Rating After Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>criteria not met</td>
<td>criteria such as the guaranteed water flow capacity, accommodation of swelling of the host bedrock, particularly Queenston Shale, or design for a 90-year service life.</td>
<td>High</td>
<td>by OPG/Hatch Mott MacDonald. • Design Review by an experienced Technical Review Committee. • Design/Build Contract includes liquidated damages for failure to achieve the agreed diversion capacity (Guaranteed Flow Amount) valued to compensate OPG for the reduced energy production throughout the 90-year service life. • Performance/warranty bonds and/or letters of credit provided by the Design/Build Contractor.</td>
<td>High</td>
</tr>
<tr>
<td>Serious construction accident</td>
<td>There are many safety hazards associated with tunnel construction that need to be identified and appropriately managed (steep grades, slips and falls, falling objects, water hazards, confined space, truck traffic, operating machinery, noise, dust, etc.)</td>
<td>High</td>
<td>• Safety program / performance was a significant factor in contractor pre-qualification • Contractor required to develop and submit an acceptable comprehensive site specific safety plan prior to start of construction activities • Safety accountabilities clearly identified • Site safety monitoring by the Owner’s Representative.</td>
<td>Low</td>
</tr>
<tr>
<td>Public safety and security</td>
<td>Risk of incidents, accidents and potentially fatalities to unauthorized persons entering the construction site and gaining access to areas and activities having High MRPH hazards.</td>
<td>High</td>
<td>• Contractor to implement an approved site-specific Security, Public Safety &amp; Emergency Response Plan that is consistent with the Niagara Plant Group’s managed system. • Site safety monitoring by the Owner’s Representative.</td>
<td>Low</td>
</tr>
</tbody>
</table>

The Business Case also included a number of risks that could have an impact primarily on the longer-term business or financial outcomes of the Project:
Table 3.4

<table>
<thead>
<tr>
<th>Risk</th>
<th>Consequence</th>
<th>Rating Before Mitigation</th>
<th>Mitigation</th>
<th>Rating After Mitigation</th>
</tr>
</thead>
</table>
| Inability of OPG to fully recover the Project costs through the Regulated Rate | Adverse financial impact on OPG                                             | Low                      | • Demonstrate prudence in managing Project cost through a comprehensive cost control process  
  • Project costs include a contingency allowance which corresponds to a 90% confidence level that the Project will be completed within the estimated costs. | Low                     |
| OPG has retained the hydrologic risk (uncertainty regarding Niagara River flow). | Incremental average annual energy output from the SAB complex could be less than 1.6 TWh resulting in a need to increase base load hydroelectric energy rates to recover Project costs. | Medium                   | • Financial sensitivity analyses demonstrate that the Niagara Tunnel Project remains competitive with future renewable electricity supply options if less water is available throughout the expected service life.  
  • Being part of OPG's regulated hydroelectric assets, the hydrologic risk is expected to be borne by electricity customers through the water variance account. | Low                     |
| A successful claim by others in Canada or the United States to use Niagara River water available for power generation that exceeds OPG's capacity. | OPG could lose rights to use some of the Niagara River water available for power generation. | Medium                   | • Under the terms of the Niagara Exchange Agreement, the Niagara Parks Commission provided covenants securing the assurance of NPC that it would grant water rights to no party other than OPG.  
  • Complete the new tunnel so OPG has adequate facilities to utilize Canada's entitlement to water available for power generation to reduce the risk of a claim by others to unused water. | Low                     |
| The 1950 Niagara Diversion Treaty is now subject to renegotiation following a 1-year notice period. | The government in either Canada or the United States could pursue renegotiation of the 1950 Treaty to address issues raised by other stakeholders that could result in a reduction of flow available to OPG for power generation at the SAB complex. | Low                      | • No mitigation possible.                                                     | Low                     |
3.4.2 Quantitative Risk Assessment
In addition to the qualitative risk assessment, quantitative risk assessments using the Monte Carlo simulation technique were also performed. The resulting cost and schedule contingencies were selected to bring the confidence in the estimate and schedule to the 90% level\(^\text{10}\). The original $985 million approved budget therefore included a contingency of $112 million primarily to cover the subsurface conditions risk. In addition, an eight-month schedule contingency was added onto the contractual Substantial Completion date of October 2009, bringing the original committed in-service date to June 30, 2010.

3.5 Superseding Business Case
During the first year of tunnel construction, the progress of tunnel excavation by Strabag was much slower than had been expected. Initial delays were caused by start-up problems with the TBM. As work progressed into 2007, there was significant overbreak in the tunnel crown within the Queenston Shale formation, which made it difficult to excavate and support some parts of the tunnel. In accordance with the mechanism provided in the Design-Build Agreement with the Contractor, a Dispute Review Board (DRB) hearing in 2008 reviewed the actual subsurface conditions compared to those that were anticipated and included as part of the DBA. The DRB concluded that Differing Subsurface Conditions had, in fact, been encountered. After an assessment of its options, and based on the DRB recommendations, OPG renegotiated the original DBA with Strabag into a “target cost/target schedule” contract called the Amended Design-Build Agreement (ADBA) which is described in more detail in Section 4.4.5.

A Superseding Business Case for approval of a revised total Project cost estimate of $1.6 billion and revised completion date of December 2013, based on the ADBA, was prepared and submitted to the OPG Board of Directors in May 2009. Upon Board approval, the ADBA, with an effective date of December 1, 2008, was executed in June 2009. It should be noted that the Contractor continued with tunnel mining throughout this entire period.

3.5.1 Alternatives Considered
The Superseding Business Case outlined four alternatives going forward:

**Status Quo - Proceed Under the Existing DBA (Not Recommended)**
This alternative entailed a high risk that Strabag would abandon the Project due to the lack of certainty over reimbursement for the delays and costs\(^\text{11}\) already incurred, the anticipated continuing difficulties in boring through the Queenston Shale, and expected liquidated damages costs. It was considered highly probable that this alternative would have resulted in a need to have the tunnel completed by another contractor at

\(^{10}\) That is, the contingencies were chosen such that when they were included there would be a 90% probability that the project cost would be under the approved estimate and would be in-service within the approved target date.

\(^{11}\) Strabag had estimated that it had lost $90 million to that point in the project.
additional and unknown cost and with further delays. Also OPG could have expected to incur additional costs for legal proceedings. This alternative was not recommended.

**Alternative 1 - Proceed Under a Target Cost Amended DBA (Preferred Alternative)**
The Dispute Review Board had recommended in August 2008 that OPG and Strabag should “equitably” share the cost and schedule impacts. For this alternative the tunnel would be completed under the amended DBA that had been negotiated to include a target cost and target schedule as well as cost and schedule performance incentives and disincentives. Tunnel alignment would be changed as recommended by Strabag to minimize further excavation in the Queenston Shale formation. This alternative also included a new risk sharing mechanism, as well as settlement of the Contractor’s outstanding claims to November 30, 2008. The remaining cost for this alternative was estimated to be $1,137 million for a total Project cost of $1,600 million. Overall, this was expected to be the lowest cost alternative for completion of the tunnel.

**Alternative 2 - Engage another Contractor to Complete the Project (Not Recommended)**
This alternative would have involved terminating the existing DBA with Strabag and engaging another contractor to complete the tunnel. It was expected that this alternative would result in a further delay of 18 to 24 months while another contractor was engaged\(^\text{12}\) and work restarted. Experience gained by Strabag to date would have been lost. In addition, there would have been additional and difficult to predict costs, including those related to legal proceedings to recover damages from Strabag.

**Alternative 3 - Cancel the Project (Not Recommended)**
It was estimated that the cost of abandoning the Project would have been approximately $100 million in order to secure the site in a safe and environmentally acceptable state. It was also expected that there would have been a low likelihood of recovering any of the $463 million already spent through the regulated rates. The opportunity to generate 1.6 TWh per year of renewable energy from the SAB plants would have been lost.

### 3.5.2 Financial Analysis
Despite the significant increase in the Project cost estimate and the expected delay in the in-service date, the financial analysis of the recommended alternative still showed that it would be worthwhile to complete the tunnel as a regulated hydroelectric asset, provided that the additional costs would be recoverable. The following table, included in the Superseding Business Case, shows the comparative economics of the original versus the superseding release:

\(^{12}\) At the time of the Superseding Business Case, a somewhat similar situation had occurred on the Seymour Capilano twin water tunnel project in Vancouver. The original contract had recently been terminated over a dispute regarding subsurface conditions. Engaging a new contractor and restarting that project took over a year and the project cost increased substantially.
Table 3.5

<table>
<thead>
<tr>
<th>Financial Measure</th>
<th>Original Approval July 28, 2005</th>
<th>Superseding Release May 21, 2009</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>In 2009$</td>
<td>In 2009$</td>
</tr>
<tr>
<td>LUEC (¢/kWh)</td>
<td>4.8 (2005$)</td>
<td>6.8 (2009$)</td>
</tr>
<tr>
<td>Equivalent PPA (¢/kWh)</td>
<td>6.7 (2011$)</td>
<td>6.8 (2014$)</td>
</tr>
<tr>
<td>Revenue Requirements (¢/kWh)</td>
<td>5.8 (2011$)</td>
<td>5.6 (2014$)</td>
</tr>
<tr>
<td>Revenue Requirements Post Gross Revenue Charge Holiday (¢/kWh)</td>
<td>9.4 (2021$)</td>
<td>13.0 (2025$)</td>
</tr>
</tbody>
</table>

At the time of the superseding release, the Feed-In-Tariff (FIT) under the Green Energy Act for hydroelectric projects under 50 MW was 12.2 ¢/kWh. This program was deemed comparable to the “PPA” measure included in the above table, which had been used in the original Business Case, except that a FIT contract was for 40 years rather than the 50 years assumed in the equivalent PPA calculation. With the Niagara Tunnel completed at the higher cost and placed in-service in 2013, the overall revenue requirement for OPG’s regulated hydroelectric assets was expected to increase from 4.0 ¢/kWh to 4.4 ¢/kWh (2014$). A financial sensitivity analysis indicated that a going forward Project cost increase of $100 million, or a six-month Project delay, would each result in an increased revenue requirement of $0.5 ¢/kWh (2014$).

Table 3.5.1 below provides the actual results for the financial measures:

Table 3.5.1

| Financial Measure                      | Final | |
|----------------------------------------|-------||
|                                        | In 2009$ | |
| LUEC (¢/kWh)                           | 6.6   | |
| Equivalent PPA (¢/kWh)                 | 9.3 (2014$) | 9.1 |
| Revenue Requirements (¢/kWh)           | 8.8 (2014$) | 7.9 |
| Revenue Requirements Post Gross Revenue Charge Holiday (¢/kWh) | 10.8 (2025$) | 7.9 |

3.5.3 Risk Analysis

As part of the re-planning related to the renegotiated tunnel contract, OPG’s Risk Services Group conducted several quantitative risk analysis workshops in March 2009. OPG Project team and OR representatives were asked to provide individual estimates of both the likelihood and the impact of 13 “key risks” that they had previously identified. These risks included the Major Risk Events delineated in the ADBA. Six schedule uncertainty risks (TBM mining, invert concreting, infill shotcreting, arch concreting, contact grouting and pre-stress grouting) were also similarly assessed. Through a Monte Carlo analysis of these risks, it was concluded that a cost contingency of $164
million (which was included in the $1.6 billion superseding authorization) would be sufficient to cover the costs of these risks at a 90% confidence level. The revised in-service date of December 31, 2013 included a 6.5-month schedule contingency beyond the ADBA contractual Target Schedule date of June 15, 2013. This schedule contingency was based on management judgement.

4 Project Management

4.1 Planning Process

In 2004, a core OPG team under the leadership of an OPG Vice President Special Projects (the initial Project Director) was created to oversee the Niagara Tunnel Project. Prior work on the tunnel project throughout the previous decade had already established a conceptual design and routing for the tunnel, developed necessary geotechnical data, and obtained environmental approval. Therefore, a full “concept/feasibility” phase for the Project was not required and it could move directly into Project definition. Accordingly, the NTP was to be divided into two main phases:

- **Phase 1 - Planning and Procurement Phase** – including all work leading up to approval for Project execution by the OPG Board of Directors; and
- **Phase 2 – Execution Phase** – including all design, construction and commissioning work for the tunnel and related facilities through to Project closeout.

Because of their prior involvement with and knowledge of the Project, Hatch Mott MacDonald (HMM) was retained in July of 2004 to be the Owner’s Representative (OR) for Phase 1. The OR would undertake most of the detailed project planning, as well as develop the technical specifications and oversee the design-build contractor selection process, under the direction of the OPG Project Director and team.

At the request of the Project Director, a Project Definition Rating Index (PDRI)\(^\text{13}\) assessment was conducted on October 1, 2004. This assessment was intended to help identify those aspects of Project definition that would require further work as part of the overall Project front end planning process\(^\text{14}\). The PDRI review, which resulted in a score of 308, showed that there were still a number of planning gaps, most notably lack of clear definition of the business drivers and Project objectives, a need to further define the Project delivery strategy, and a need to conduct the Project risk analysis.

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\(^{13}\) The PDRI is a pre-project planning tool, developed by the Construction Industry Institute (CII) that can be used as a predictor of project success. It measures project readiness to proceed based on the assessment of approximately 70 project planning elements. An overall measure is calculated, on a 0 – 1000 scale, where a lower score is better. A score of 200 or less at the time of authorization has been correlated through CII research with a higher probability of meeting cost and schedule targets.

\(^{14}\) Although the most common use of the PDRI is to assess the level of project definition just prior to the request for authorization, it can also be a valuable tool to help define work scope early in the front end planning phases of a project.
During 2004, HMM also started development of a draft Project Execution Plan (PEP). In early March 2005, a facilitated workshop\(^{15}\) was held with the OPG/OR Project team to review the draft PEP. One other important focus of this workshop was to clarify the roles and responsibilities of the team members to ensure they were understood and agreed to. Some team members were also given a lead role in further preparation of sections of the PEP. Following this workshop, a new draft of the PEP was issued, reviewed by the team and then, with agreed changes, formalized as Revision 0 of the PEP in April 2005. All team members signed off on the PEP to acknowledge their participation in its creation.

In April 2005, a second PDRI assessment was done in preparation for the request for Project authorization by the OPG Board. Some elements of the Project still could not be completely defined until the Design-Build contract was in place, but reasonable assumptions were made based on OPG/OR team knowledge of the Project. The PDRI review resulted in a score of 115. The gaps from the earlier PDRI had all been addressed to the fullest extent possible.

With the issue of Revision 0 of the PEP and completion of the PDRI, two of the conditions mandated by the project management governance as being essential for Project release had been fulfilled. In parallel with the project management planning, the Release Quality Estimate and the financial modeling/analysis for the Business Case were also completed. The financial model was independently reviewed and verified by Access Capital for the OPG Major Projects Committee.

Following Board approval of the Project in July 2005, a second agreement was signed with HMM in September 2005 to have them undertake the OR/project management role for Phase 2 of the NTP.

In preparation for the start of project execution, a Memorandum of Understanding (MOU) was created between the Niagara Plant Group (the ultimate customer for the Project) and the OPG/OR Project team\(^{16}\). The MOU defined constraints governing how the Project would be executed, including those required to minimize the impact on NPG ongoing operations. It also defined the role of NPG in Project activities such as design reviews, safety and security management, emergency management, stakeholder relations, outage planning, etc. Development of the MOU started in October 2005 and the final document was signed off in February 2006. Amendments to the MOU were later issued in November 2010 – to document additional land to be used by the Project – and in June 2011 to include some emergency and non-emergency protocols.

\(^{15}\) This workshop was also intended as a team-building exercise for OPG and consultants participants in the project.

\(^{16}\) The MOU mechanism had been successfully used on past projects, such as the Lambton Rehabilitation Project, to improve communication and cooperation between the plant customer and an external project team.
Revision 1 of the PEP was issued in March 2006, after the Design-Build contract had been awarded and more details concerning the execution approach, including the technical design basis as well as the planned timing and sequence of activities, were known. Further revisions of the PEP were issued in March 2006, September 2010, and January 2013, in accordance with project management governance requiring new revisions to reflect any significant changes in the Project planning baseline. All revisions to the PEP were also signed off by the full Project team.

A Project Policies and Procedures Manual was developed by HMM to guide implementation of the Project Execution Plan. This manual provided more detailed instructions, primarily to OR staff, on how certain aspects of the PEP, such as project cost and schedule controls, engineering management, safety and environmental management, and construction oversight would be carried out. The procedures were periodically revised and reissued throughout the Project.

### 4.2 Objectives

In addition to the fundamental business objective listed in Section 3.1, more specific Project objectives, as stated in the Project Charter of January 2005, and expanded in subsequent versions of the Project Execution Plan, were defined as listed below:

<table>
<thead>
<tr>
<th>Objective</th>
<th>Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintain a safe working environment</td>
<td>Complete the Project with zero fatalities, zero critical injuries, and zero lost time injuries while maintaining the safety of the public at all times</td>
</tr>
<tr>
<td>Meet all environmental and mitigation requirements</td>
<td>Meet the commitments contained in the Environmental Assessment (EA) and the conditions of the EA Approval, all legislated environmental and mitigation requirements and provide, at Project completion, minimal long-term environmental obligations to the OPG Niagara Plant Group</td>
</tr>
<tr>
<td>Maintain the Project on schedule and within budget</td>
<td>The Project was to be maintained within the approved schedule and budget. Decisions regarding any deviation from approved budget and/or schedule would be based on the net business impact, considering the tradeoff between Project cost and business revenue.</td>
</tr>
<tr>
<td>Achieve a high overall quality of design and construction, meeting performance requirements</td>
<td>It was intended that the design and construction of the Project provide for a 90-year service life for key elements of the facility such as the tunnel, intake structure and outlet structure, and would not result in</td>
</tr>
</tbody>
</table>
| Maintain a good working relationship with stakeholders, contractors and the affected public. | any forced outages during that period. Other components of the Project would be designed and constructed to meet existing legal requirements. The contract would require the tunnel contractor to specify and meet a measured flow through the tunnel at completion. This was established as 500 m$^3$/s. | Priority would be given to maintaining good working relationships with stakeholders, contractors, and the affected public during planning and construction of the Project. A key objective was to minimize Project impact on the ongoing operations of Niagara Plant Group. Measures of this objective included:  
- Zero Treaty violations concerning Falls flow  
- Zero International Niagara Board of Control (INBC) Directive violations concerning Grass Island Pool (GIP) operation  
- Zero ice management incidents  
- Zero forced outages at existing diversion and generation facilities  
- Optimal planned outages coordinated with Niagara Plant Group outage plans  
- Maintenance of positive relationships with regulators and host communities  
- Maintenance of ISO 14001 registration  
- Maintenance of BSA 18000 registration.  
- Minimize ongoing (post-Project) monitoring requirements by NPG |
| Ensure sufficiently detailed reporting to the OPG Board of Directors and the Province of Ontario such that their confidence in OPG’s ability to execute large projects was maintained. | No specific measures or targets were defined for this objective. |
4.3 Scope
As noted earlier, the NTP was divided into two phases:

Phase 1 – Planning and Procurement
Key deliverables for the phase leading up to full Project authorization included tunnel contract bidder pre-qualification, contractor selection, executed Design-Build contract, essential permit and approval submissions, third party agreements, designs for enabling work, a Release Quality Estimate (RQE), and Business Case development and submission for Phase 2 approval by OPG’s Board of Directors.

Phase 2 - Execution
Key deliverables included: the completion of permits and approvals; detailed design and construction of the diversion tunnel and associated facilities; tunnel commissioning and placing into service; performance testing; and Project closeout including a closeout report and transfer of permanent records to OPG/NPG.

The Project scope was made up of the following elements:

4.3.1 Third Party Requirements
Third party requirements included: the work necessary to meet the conditions of the EA approval; pre-construction permitting; communication with the public; adherence to the Community Impact Agreement between OPG and local municipalities; and adherence to the MOU with the Niagara Plant Group.

4.3.2 Tunnel Contract
Establishment of the Design-Build contract included: the prequalification of potential bidders; development of the contract terms and conditions; development of technical specifications including the Owners Mandatory Requirements; establishment of an agreed Geotechnical Baseline Report with the Contractor; and management of the bidding, evaluation and negotiation process up to selection of the preferred contractor. The formal contract agreement would be signed after Project approval by the OPG Board of Directors and when Project financing was in place.

4.3.3 Tunnel and Facilities Construction
Construction of the tunnel was done using a tunnel boring machine (TBM). The direction of tunneling was from the outlet to the inlet, and the original route generally followed the line of the two existing tunnels, under the City of Niagara Falls.

4.3.3.1 Intake Area
The Intake Area work upstream of Niagara Falls included:
- Setting up the Contractor’s lay down area, shops and offices using available space along the Niagara Parkway;
- Creation of a new separate access road out to Portage Road;
- Installation of temporary traffic signals on the Niagara Parkway at Portage Road to minimize impacts on through traffic during construction; and
- In-water excavation of the intake channel, installation and removal of a cofferdam, removal of the existing ice accelerating wall and construction of a new wall, closure of the downstream Bay 1, and construction of portions of the intake approach wall.

### 4.3.3.2 Intake Structure

This work included design and construction of a reinforced concrete intake structure underneath the INCW, upstream of the Falls. The new structure can house the service gates for closure of the tunnel at the upstream end. The tunnel can be isolated from the upper Niagara River for dewatering by installing the sectional steel intake gates in steel guides embedded in the intake structure. Removable steel guide towers are provided to enable the gate sections to be installed by a mobile crane.

A cofferdam had to be constructed to allow for the intake excavation. Prior to cofferdam construction, a new accelerating wall, used for ice management at the intake, was constructed and the existing accelerating wall demolished and removed. The cofferdam was removed after completion of the intake works and removal of the TBM.

Work at the intake also included grouting of the rock formations above the tunnel entrance to minimize water inflows into the tunnel during the TBM drive through these formations. In addition, underwater excavation of an intake channel was required upstream from the intake structure and beyond the confines of the cofferdam.

### 4.3.3.3 Diversion Tunnel

The tunnel was excavated using a 14.44 m diameter open gripper TBM manufactured by the Robbins Company. The TBM was shipped in parts and assembled for the first time at the NTP site. Excavation started at the tunnel outlet (SAB) end. The tunnel was originally to be constructed in two passes with the first pass consisting of tunnel boring followed by erection of an initial lining consisting of shotcrete, mesh, bolts and ribs\(^{17}\) to support the excavation. Once the complete tunnel was excavated and the TBM removed, a cast-in-place concrete final lining between 600 and 700 mm thick would be constructed. This plan was later modified so that construction of the final liner proceeded concurrently with and behind the tunnel boring. The invert (lower part) of the lining was installed first, followed by the arch, or upper section, of the lining. To avoid water leakage\(^{18}\) into the surrounding rock formations, an impermeable polyolefin

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\(^{17}\) Strabag’s initial plan to use a ring erector to install steel reinforcing rings as part of the initial support structure as the tunneling progressed was abandoned early in the tunnel drive due to their inability to get the ring erector equipment to work properly.

\(^{18}\) The design had to prevent contact of fresh water from the tunnel with the surrounding shales. Otherwise there would be swelling of the rock surrounding the tunnel which would lead to unacceptably high stresses on the structure.
membrane was installed between the initial shotcrete and final concrete lining to ensure watertightness of the tunnel. The final lining was prestressed using high-pressure grout injected between the impermeable membrane and the initial lining.

Dewatering shafts were constructed at the low point of the tunnel to permit future inspection or maintenance, if required.

Because of the difficulties and delays encountered in safely excavating and supporting the section of tunnel in the Queenston Shale formation, part of the tunnel was rerouted midway through the Project to minimize the length passing through the Queenston Shale. To allow for this upward vertical realignment out of the Queenston Shale, the horizontal alignment was shifted about 200 m eastward, directly below Stanley Avenue and out from under the two existing tunnels. This also shortened the tunnel length by about 200 m to 10.2 km.

On completion of the tunnel, an independent third party performed a flow test to establish whether the tunnel met the flow guarantee. The Design-Build contract terms included liquidated damages or bonuses based on the measured flow versus the guarantee.

4.3.3.4 Outlet Area
The main construction facilities were at the tunnel outlet end on OPG’s property, between the PGS Reservoir and the existing SAB2 canal. A new road connection to Stanley Avenue was constructed. The Regional Municipality of Niagara installed temporary traffic signals at the intersection with Stanley Avenue on behalf of OPG.

4.3.3.5 Outlet Structure and Channel
The outlet channel was excavated using drill and blast methods. This channel was initially used as the TBM staging and assembly area. Connecting the channel to the tunnel is a reinforced concrete structure, housing a vertical lift gate for closure of the tunnel. The lift gate has five articulated structural steel sections running on steel wheels bearing on steel roller paths embedded in the concrete structure. The inlet structure also has provision for installation of sectional service gates downstream of the lift gate. A surge shaft in the transition from the tunnel to the outlet is designed to contain any surge that occurs during outlet gate closure under flowing water conditions, and also provides access for inspection when the tunnel has been dewatered. Water from the diversion tunnel discharges through the excavated channel into the existing canal system feeding the SAB complex. The PGS Dewatering Structure was also removed and services (e.g. power cables, water main) that had been on the structure were re-routed.
4.3.4 Enabling Activities and Miscellaneous Construction
A number of enabling activities had to be performed before the start of the tunnel work:

- Establishing expropriation rights to the tunnel route as allowed under Bill 100, *Electricity Restructuring Act*, Section 51;
- Conducting land surveys to determine the location of property required for the tunnel;
- Expropriating subsurface rights to privately owned property, and notifying owners;
- Expropriating subsurface property rights from the City of Niagara Falls and the Regional Municipality of Niagara. The majority of these properties consisted of road crossings;
- Acquiring, through negotiated agreements, the necessary surface and subsurface property rights from the Niagara Parks Commission;
- Acquiring, by negotiated agreement, the necessary subsurface rights to the underground crossing of railway corridors owned by Canadian National and Canadian Pacific Railways. OPG did not have the right to expropriate these properties;
- Completion of various access road improvements and utility relocates at the inlet and outlet areas. The Regional Municipality of Niagara (RMON) carried out the roadwork on behalf of OPG under the Community Impact Agreement; and
- Surveying a number of structures near the site before the start of construction to establish a basis for determining if the structures had been affected by the construction activities such as blasting, and to determine responsibility for repair, if necessary. OPG/NPG and the Contractor were required to endorse the preconstruction survey before the start of construction activities that could result in damage to the existing SAB, PGS or INCW facilities.

Prior to contract completion, post construction work included decommissioning of temporary gas, electrical, telecom, and sewer connections installed for construction of the tunnel.

4.3.5 Project Management
Management of the Project was a combined responsibility of OPG and the OR working together as a team, under the authority the OPG Project Director. Most of the Project management team members, including the Project Manager, were supplied by the OR. A detailed Responsibility Matrix was used to assign the specific project management task responsibilities.

4.3.6 Exclusions
Specifically excluded from the Project scope were:
- Dewatering pumps for the tunnel;
• Sectional service gates at the outlet; and
• Permanent closure of the adit excavated in the 1990s for geotechnical investigations related to SAB3 development.

4.4 Project Delivery Strategies

4.4.1 Owner’s Representative
At the time the Project was restarted in 2004, it was recognized that OPG did not have the technical capability or staff to manage a tunnelling project of the magnitude of the NTP. Therefore, as is common with projects of this type, OPG decided to retain an Owner’s Representative (OR) to provide project management services as well as detailed oversight of the engineering, construction and commissioning of the tunnel. The OR services were initially procured in July 2004 for Phase 1 and a subsequent agreement in September 2005 extended the services to cover Phase 2 of the Project. An amendment to the OR contract was executed in January 2010 to reflect the new Amended Design-Build Agreement with the Contractor and to extend the duration and cost of the OR services to a new final completion date of December 31, 2013.

The OR services were provided by Hatch Mott MacDonald in association with Hatch Acres (HMM). OPG chose HMM to be the OR on a sole source basis for the following reasons:

• Hatch Mott MacDonald had recognized expertise in tunneling;
• Hatch, working with Acres Bechtel, had acted as the OR when the Project was under development in 1998 and OPG had been pleased with Hatch’s performance;
• Acres, which was purchased by Hatch in June 2004, had provided engineering support on the proposed SAB 3 and the tunnel design since 1991;
• The sub-surface risks of this Project had been investigated and analyzed by Acres and Hatch. As a result, Hatch had considerable prior knowledge about the Project, including the geological risks; and
• Hatch is Canadian owned and headquartered in Mississauga, giving OPG convenient access to senior Hatch staff. The contract specifically named the individual who would be the HMM Project Manager, with provisions for OPG approval of any replacement.
The OR led or participated in all aspects of the Phase 1 (Planning and Procurement) work including:

- Identification and pre-qualification of bidders;
- Development of the RFP documents including the Owner’s Mandatory Requirements, Geotechnical Baseline Report, commercial terms, etc.;
- Preparation of proposal evaluation criteria;
- Bid evaluation coordination;
- Negotiation with proponents and finalization of the DBA with the selected Contractor;
- Development of permitting submissions required prior to Project authorization
- Preparation of the Project Execution Plan and Release Quality Estimate.

In Phase 2 (Execution) the OR provided:

- Oversight and monitoring of engineering design and construction on behalf of OPG;
- Contractor drawing and data submittal reviews\(^\text{19}\);
- Full time, on-site quality oversight of tunnel construction against Project drawings, specifications and installation plans;
- Recording of the Contractor’s daily work activities and progress;
- Contractor quality audits;
- Health and safety oversight, monitoring and auditing where the Contractor was the Constructor under the OHSA;
- Health and safety management on behalf of OPG, where OPG was the Constructor for the Intake Part Project;
- Environmental management oversight of the Contractor;
- Additional engineering studies or investigations, where required, either directly or through subcontractors;
- Project cost and schedule controls;
- Weekly and monthly Project reporting;
- Review of the Contractor’s applications for progress payments prior to submittal to OPG; and
- Assistance to OPG in the negotiation of the Amended Design-Build Agreement.

### 4.4.2 Design-Build Agreement

For major engineering and construction projects, the two most common delivery strategies are Design-Bid-Build and Design-Build. The Design-Bid-Build approach

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\(^\text{19}\) Some detailed designs were also reviewed by OPG/ NPG/ Hydro Engineering, specifically those pertaining to intake and outlet gates, hoists and associated mechanical, electrical and control systems, including operation, maintenance and handling aspects.
involves having the owner (often with the assistance of a consultant) first prepare
detailed design and construction specifications and then, usually through a competitive
tendering process, retain a construction firm to build the facility to the pre-established
design. Under Design-Build, the owner contracts with a single entity to design and
construct the facility to meet its pre-established requirements. OPG had previously
started to use the Design-Build approach in the 1998-1999 RFP process for design and
construction of the tunnel. This method was again chosen in order to:

- Reduce project management complexity by providing OPG with single-point
  accountability through the Contractor for all aspects of Project design and
  construction, including much of the permitting;
- Minimize Project duration, by eliminating the need to contract sequentially for
design and construction services;
- Take advantage of the design and construction expertise of contractors
  specializing in tunnelling work;
- Fully integrate constructability considerations into the design;
- Appropriately allocate Project risks; and
- Obtain as much upfront price certainty as possible.

In order to ensure that the tunnel would meet OPG’s long-term needs and
commitments, a set of “Owner’s Mandatory Requirements” formed the basis of the
specifications in the Request for Proposals and the subsequent Design-Build Agreement
(DBA). This document was essentially a functional and performance specification
describing key technical parameters of the facility such as required flow rate, tunnel
service life, and essential technical standards to be met, as well as known constraints
such as the need to use a TBM to meet the EA approval conditions. The RFP requested
proponents to prepare a proposal conforming to these mandatory requirements but
reflecting their own knowledge and experience in tunnel construction.

Four pre-qualified firms were invited to bid, and proposals were received from three
consortiums:

- Niagara Tunnel Constructors made up of Hochtief, Aecon, and Vinci with
  engineering by Hochtief & Klohn Crippen;
- Niagara Tunnelers made up of Obayashi and Kenaidan with engineering by
  Jacobs, Black & Veatch and Golder Associates; and
- Strabag AG made up of Strabag, with Dufferin as a subcontractor for all the non-
tunnel works such as the inlet and outlet structures, and engineering by ILF and
  Morrison Hershfield.

Strabag, the successful bidder, also had a number of subcontractors for equipment
supply, including:

- The Robbins Company (USA) for design, manufacture and delivery of the TBM;
• ROWA (Switzerland) for design, manufacture and supply of the TBM trailing gear and equipment; and

• BMTI/Baytag (Austria/Germany) for design, manufacture and supply of the main structural components for the invert and arch carriers and shutters. Baytag provided the design for the restoration carriers\(^{20}\) with manufacture and supply of the main structural components by Burnco (Markham, ON).

In addition to having a competitive price, Strabag was selected on the basis of having what was judged to be a technically superior proposal for providing an impervious tunnel lining that would prevent water leakage into the surrounding Queenston Shale. Strabag’s TBM supplier also had a TBM main bearing available which would shorten the delivery time for the machine by several months.

The negotiated Design-Build Agreement met the single point accountability objective by allowing OPG and the OR to deal with a single entity (Strabag) that in turn managed all of the other related subcontractors. The subcontractors provided the specialist expertise required to execute various aspects of the total facility Project design and construction such as the intake and outlet channels and structures.

Because the Project had been deferred once before, after the 1999 Request for Proposal process had been initiated, there was concern that potential bidders might be reluctant to go to the trouble and expense of again preparing bids for a Project that had not yet been approved. Therefore it was decided that an honorarium of $600,000 would be paid to each proponent that submitted a proposal but was not the successful bidder. This strategy was instrumental in obtaining the three proposals from the RFP process.

4.4.3 Geotechnical Baseline Report
One of the most significant risk drivers for tunnel construction is the lack of complete knowledge of the subsurface rock conditions along the tunnel route. Geotechnical investigations can, at best, provide only a sample of these conditions. For the NTP there were known concerns, particularly regarding the rock conditions under the buried St. David’s Gorge and the high horizontal stresses within the rock of the Queenston Shale formation. Therefore, a significant consideration in the formation of the DBA would be establishing a reasonable basis upon which OPG would assume an acceptable portion of the risk of encountering “Differing Subsurface Conditions” (DSC) during construction.

In order to ensure agreement between OPG and the Contractor on the likely subsurface conditions to be encountered during tunnel construction, a 3-step approach was used:

\(^{20}\) The restoration carrier was a special piece of equipment used in rebuilding of the tunnel overhead profile where overbreak of the surrounding rock had occurred during tunneling.
1. Results of the extensive previous geotechnical studies conducted by OPG and its consultants were included in the RFP documents in the form of a Geotechnical Baseline Report, designated as “GBR A”.

2. The contract proponents were required to prepare and submit with their proposals their own geotechnical assessments, designated as “GBR B”.

3. OPG and the successful bidder jointly agreed on a final set of baseline geotechnical conditions, designated as “GBR C”, that were intended to form the reference for any claims by the Contractor that the subsurface conditions encountered were more adverse than those expected and documented in GBR C.

The DBA included a Dispute Review Board (DRB) mechanism for reviewing and resolving claims related to the contract. The DRB was comprised of three independent and recognized tunneling experts who were kept informed of the Project progress. The GBR C was intended to provide the basis for assessing Contractor DSC claims, as well as any other claims that could not be resolved by mutual agreement, and deciding on the extent to which OPG or the Contractor would be responsible for additional costs or delays related to such claims.

4.4.4 Contract Price and Schedule

For major construction projects, several compensation approaches are possible, ranging from lowest to highest assumed cost certainty as follows:

- Time and materials (or “cost plus”) – lowest up front cost certainty;
- Cost plus fixed fee;
- Unit price;
- Guaranteed maximum price; and
- Firm price (or “lump sum”) – highest up front cost certainty.

Selection of the appropriate approach generally reflects the owner’s trade-off between the predictability of cost (and schedule) and the degree to which the owner wishes to be directly involved in, or have control over, the project including the ability to make changes during execution. In addition, the extent of up front cost and schedule predictability will be related to the level of scope definition, design completion and knowledge of project conditions at the time the contract is formed. The overall objective in selecting a delivery strategy and compensation approach is to try to appropriately allocate the project risks to the parties best able to manage them, thereby resulting in the optimum price/cost for each party.

For the NTP a fixed price approach was initially chosen for the original DBA, although as is common in large construction projects, provisions were made in the contract for

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21 Most of these studies had been carried out during conceptual phase investigations for the proposed SAB 3 between 1983 and 1989. Further work was subsequently done for the definition phase between 1991 and 1993 and again from 1994 to 1996. All of these investigations were documented in a 12 volume Geotechnical Data Report that was made available to the tunnel project proponents prior to proposal submission and formed the basis of the GBR A.
possible price changes due to approved changes (Project Change Directives). The overall intent of the fixed price approach was to provide as much up front cost certainty as possible, with the residual cost risk being addressed by OPG’s Project contingency. Under a fixed price arrangement, the Contractor’s actual costs would not be available to OPG, and monthly payments were to be made against Project completion percentages according to a cost breakdown in the contract, as verified by the OR.

To establish higher schedule certainty, the contract included a required Substantial Completion Date, with bonuses for early completion and liquidated damages to compensate OPG for any delays. The residual schedule risk was addressed by building a schedule contingency into the OPG Project plan.

4.4.5 Amended Design-Build Agreement (ADBA)

In May 2007, as the TBM mining had advanced approximately 840 m to the top layer of the Queenston Shale, a large rock block fell and damaged the TBM. Tunnelling was stopped for more than three weeks, while the rock was removed and the damage repaired. As a result, Strabag filed a claim (Project Change Notice 17) for Differing Subsurface Conditions. Throughout the next several months, progress continued to be very slow due to extensive overbreak and the need to install spiles ahead of the TBM to provide rock support during tunnelling. Tunnelling productivity was approximately 25% of the original estimate and the Contractor was forecasting a significant delay in the tunnel completion date. In the fall of 2007, Strabag requested that OPG consider allowing a change in tunnel alignment to enable the TBM to move out of the Queenston Shale formation earlier. After many discussions between OPG and Strabag, a decision was mutually made in early 2008 to take the as-yet unresolved PCN17 claim, as well as other DSC issues, to the DRB. Two days of hearings were held with the DRB in June 2008, during which OPG and Strabag presented their positions regarding the dispute. The DRB decision was issued in August 2008. The DRB upheld Strabag’s claims regarding excessive overbreak and the inadequacy of the table of rock conditions in the GBR, while accepting OPG’s positions on the other issues. Two key DRB recommendations were that:

“... the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible.”

and

22 Since the original tunnel route was directly under the existing SAB tunnels, a horizontal realignment in an easterly direction was necessary to allow the tunnel vertical alignment to be changed to a higher elevation. This also shortened the tunnel by 200 m.

23 These issues included large block failures, ground conditions under the St. David’s Gorge, insufficient stand-up time, excessive overbreak and inadequate table of rock conditions and characteristics.
“... that the Parties jointly revise the Table of Rock Conditions and Rock Characteristics in such a manner that it describes the rock characteristics to be assumed in terms that are mappable (or otherwise quantifiable) so that it can serve as a clear basis for defining DSCs throughout the remainder of the tunnel excavation.”

After consideration of the alternatives available (see section 3.5.1), OPG decided to renegotiate the contract with Strabag and develop an Amended Design-Build Agreement. Initially Strabag proposed two options for this:

Option A: Continue with the “fixed price” DBA with cost adjustments for measures needed to deal with the expected rock conditions going forward including rock support provisions for dealing with overbreak, tunnel profile restoration, modifications to the TBM, as well as extension of the Project schedule, and settlement of pending claims. This option also would eliminate or modify the liquidated damages for delay and early completion bonus provisions in the contract. Strabag estimated that their total contract price for the tunnel would increase from the original $622.6 million to $910 million under this scenario.

Option B: Convert the fixed price contract to a target price/schedule contract with cost savings and benefits from early completion (relative to a new target date) to be shared equally between Strabag and OPG. An included overhead fee, proposed initially by Strabag to be 12%, would be decreased to zero if the contract cost reached $1 billion or the Project was six months later than the new committed completion date. The expected contract price for this option would be $856 million.

After internal discussions within OPG and with the OR, and consideration of Strabag’s proposed options, a decision was made by OPG to pursue renegotiation of the agreement with the following provisions:

- A lump sum payment to be made by OPG to settle Strabag’s costs and claims to November 30, 2008;
- A revised contract, to be effective as of December 1, 2008, and to include a negotiated target price and schedule (similar to Strabag’s option B); and
- Incentives and disincentives in the amended contract to ensure completion of the work.
With Strabag’s concurrence, a multi-step process was adopted to develop the amended agreement. This included:

- Creation of a set of “Principles of Agreement” between OPG and Strabag; this included a commitment by OPG to settle the outstanding claims;
- Negotiation of a Term Sheet reflecting the Principles of Agreement;
- Negotiation of a Memorandum of Understanding establishing the target schedule and a second MOU establishing the target cost; and
- Negotiation of necessary contract changes to convert the original DBA to a target cost agreement.

This approach provided enough financial certainty to Strabag to allow construction of the tunnel to continue without interruption while final details of the ADBA were worked out. The ADBA was signed in June 2009 but made effective as of December 1, 2008. At this point, the tunnel drive was approximately 50% complete.

In the ADBA OPG and Strabag agreed on a target cost of $985 million, a target Substantial Completion date of June 15, 2013 and changes to the allocation of risk. Strabag would be entitled to its “Allowed Costs”, plus a 5% overhead recovery fee, to complete the Project. In addition, Strabag would be paid an Interim Completion Fee of $10 million upon completion of TBM mining activities and $10 million upon achieving Substantial Completion. Under the ADBA, Strabag’s actual tunnel construction costs were “open book”, i.e. subject to verification and audit by OPG and the OR.

The agreement included a cost performance incentive/disincentive of 50% of the difference between Strabag’s actual cost and the target cost, as adjusted for approved changes. The ADBA also included a schedule performance incentive of $200,000 per day for each day that Substantial Completion occurred before the target date of June 15, 2013 (again as adjusted for approved changes) and a disincentive of $67,000 per day that the Substantial Completion date went beyond the target date. The aggregate limits of the incentives and disincentives were to be $40 million and $20 million respectively.

The ADBA provided a detailed mechanism for adjustment to the target cost and schedule due to various causes such as OPG requested changes, force majeure events, changes in the law, etc. In addition, should any of nine “Major Risk Events” (such as

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24 Strabag had claimed losses of $90 million. OPG agreed to pay Strabag $40 million to resolve all issues to November 30, 2008 as an effort to share the losses. As a good faith gesture, OPG committed to make the payment within 15 days of signing the principles; however, Strabag was required to provide a $40 million letter of credit in case a final agreement was not reached. OPG also had the right to audit Strabag’s losses and to the extent that the $90 million was not substantiated in the audit, the $40 million payment could be reduced proportionately.

25 “Allowed Costs” did not include such items as head office costs, interest costs, certain insurance deductibles, costs for warranty work, costs to correct or remove a defective part of the project, and third party liability.

26 The ADBA defined Actual Cost as the $302M paid to Strabag prior to December 1, 2008 plus the accumulated Allowed Costs from December 1, 2008 onwards, minus any proceeds from the sale of assets and any insurance payments received by Strabag.
TBM main bearing failure) occur, the ADBA defined a pre-determined allowed cost of
schedule impact, set out in a “Major Risk Table” which formed part of the agreement.
The Dispute Review Board from the original contract was replaced by a Steering
Committee of senior OPG and Contractor executives to initially consider any disputes. If
this committee could not reach agreement, the contract allowed for arbitration as the
next step for resolution.

The ADBA, with three subsequent amendments (June 29, 2012, October 16, 2013 and
February 3, 2014), remained in effect for the remainder of the Project.

4.4.6 Team Building
OPG’s Project leadership recognized at the outset of the Project that there was a need
to establish shared objectives and commitments and to build trust between the various
parties participating in the Project. Therefore, an initial team building meeting was held
between the OR staff and OPG in early 2005 to establish Project goals and to discuss
responsibilities for specific aspects of the project planning and procurement phase
work.

The DBA also contained a provision for holding – on a voluntary basis – a team building
session with the Contractor. A team building session was held with key staff of OPG, the
OR and the Contractor in January 2006. The purpose of this session was to improve
communication between all parties, and to facilitate problem solving, conflict avoidance
and issue resolution. Follow-up workshops, events, and activities were held periodically
with Contractor and OPG/OR staff.

4.5 Project Controls
The OR, on behalf of OPG, managed Project schedule and cost controls for all elements
of the Project.

4.5.1 Schedule Management
Prior to Project release, the OR had prepared an initial Level 2 critical path schedule
using Primavera P3®. After award of the DB contract and receipt of the Contractor’s
scheduling information, the Contractor’s detailed schedule was incorporated into the
overall Project P3 schedule to form the Project baseline schedule. Schedules used for
Project reporting were displayed in Gantt chart format.

From the outset, the Contractor used two scheduling methods. The aboveground work
at the intake and outlet ends, which was executed by Strabag’s subcontractors such as
Dufferin Construction, was scheduled in Primavera P3®. Strabag itself used the
Time/Way diagram method as its primary tool to plan and schedule the underground
tunnel boring work and converted the information into P3 for transmittal to the OR and
OPG.
Time/Way diagrams, known also as “time-distance” diagrams, are used to plan projects such as roads, pipelines, tunnels, and high-rise buildings, where repetitive work activities can proceed sequentially along a linear path. Activities on the Time/Way diagram, including mining and the various components of waterproofing and liner installation, were plotted graphically along a horizontal distance (chainage) axis, according to their relative linear position, and against a vertical time axis. This allowed showing not only the relative location of the activities but also the direction of progress (e.g. either from the intake or the outlet end of a tunnel) and the planned/actual progress rates. Reading such a diagram along a horizontal (time) coordinate would show the point at which work had been planned or had progressed for each of the sequential activities.

Early versions of the Contractor’s P3 schedule were deemed unacceptable by the OR and were returned for revision on several occasions. This was partly due to the use of relatively inexperienced Contractor staff to prepare the initial P3 schedules.

Based on actual progress observed by OR construction management staff on the work site, and monthly progress reports submitted by the Contractor and other Project participants, the OR updated the overall Project schedule each month and calculated a Schedule Performance Index\textsuperscript{27} (SPI) for both the tunnel drive and the overall Project using earned value methods.

Early in the tunnel drive, TBM start-up problems delayed the initial rate of progress. As the tunneling proceeded the Contractor encountered rock support problems, including a fall of ground (partial tunnel roof collapse at one location) in May 2007, and progress fell further behind the initial schedule. An early major change in the Contractor’s plan was to begin installing the tunnel lining concurrent with and behind TBM mining rather than following completion of the full tunnel drive as had originally been planned. Even with this change, as problems continued, the Contractor’s revised schedules showed progressive slippage of the completion date. By September 2007, when the tunnel drive was still only 10% complete, it became clear that the entire Project schedule contingency had been consumed, and the in-service date originally approved by the Board would not be achievable. As part of the negotiation of the Amended Design-Build Agreement, a new schedule and a modified approach to scheduling were adopted.

The basis of the new schedule for the ADBA was a revised Time/Way Diagram reflecting expected levels of tunneling productivity through the various rock layers in the modified routing. From this diagram, a new schedule was developed and agreed to by the Contractor, OPG and the OR as the basis of the ADBA. The new schedule included two key dates tied to contractual schedule performance incentives/disincentives:

\textsuperscript{27} SPI = Earned Value/Planned Value, or, Budgeted Cost of Work Performed/Planned Value of Work Performed. It is a measure of schedule efficiency with values ≥ 1 indicating that the project is on or ahead of schedule. Assuming constant productivity going forward, the SPI can be used to forecast overall project duration.
completion of the tunnel drive (i.e. TBM breakthrough); and Substantial Completion (i.e. first operation with full water flow).

Each month, the Contractor would provide to the OR an update of the P3\textsuperscript{28} schedule in electronic format showing progress to date, and the projection to completion. Start and completion dates for each activity, as well as any new activities added to the schedule, were also shown. In addition, the Contractor would provide the updated Time/Way diagram used to update the Project schedule. The scheduling information, including the SPI, was included in the detailed monthly progress reports prepared by the OR for OPG Project staff and senior management. The OR was able to develop a method for calculating the SPI directly from the Time/Way diagram.

Prior to March 2010, the SPI was calculated and reported for each major construction activity (e.g. tunnel mining, invert concrete liner, overbreak repair). In March 2010, OPG instructed the OR to provide an “overall” SPI for the entire Project in addition to the individual SPI calculations for each construction component. Initially the overall SPI was based on every Project activity, including office and general costs. However, in a 2010 audit, OPG Internal Audit pointed out that this method could cause the SPI to be distorted by progress on non-critical path items. This would make its value in calculating the final Project duration questionable. In May 2010, as a result of these observations, the progress reporting was modified to report the overall SPI against activities on the Project critical path.

4.5.2 Cost Management

4.5.2.1 Estimating

Costs were estimated and managed by the OR using a hierarchical Cost Breakdown Structure (CBS) that corresponded to the Work Breakdown Structure (WBS) for the Project. Immediately below the highest (overall Project) Level, the Level 2 elements of the WBS/CBS were:

1. OPG costs (e.g. Project management, NPG support)
2. Professional Services costs (OR, risk assessment, land surveying)
3. Third Party costs (e.g. Community Impact Agreement)
4. Miscellaneous construction costs (e.g. groundwater monitoring wells)
5. Tunnel Facilities Contract (DB contract)
6. Other costs (e.g. Welland River issues)
7. Retirements/Niagara Exchange Agreement costs (i.e. Ontario Power/Toronto Power demolition and construction)

These WBS/CBS elements were then further broken down into Level 3 work packages, Level 4 components and Level 5 activities.

\textsuperscript{28} Midway through the project the Contractor switched from the P3 version of Primavera to P6. This caused some short-term file incompatibility problems for the OR.
Interest and contingency costs were calculated for each of the Level 2 WBS/CBS elements. This would allow for accurate cost allocations to OPG’s asset accounts for the overall tunnel facility.

In preparation for the ADBA negotiations, the OR developed a very comprehensive Excel®-based cost model for the tunnel work. This model was used to check the estimates prepared by the Contractor. In most cases the OR and Contractor were able to reconcile their individually prepared estimates, which were fully disclosed to one another. However, for some items such as the estimated quantity of overbreak, cost of diesel fuel, or inflation rates, it was agreed to “baseline” the estimate to establish a reference cost, and then include a mechanism in the ADBA to adjust the final price once the real quantities or costs were known. Through this approach, OPG, the OR and Strabag were able to converge on a mutually acceptable – and ultimately quite accurate – target cost for the ADBA.

4.5.2.2 Cost Control

The OR was responsible for detailed Project cost monitoring, reporting and forecasting. Key features of the cost management process were as follows:

- Excel® was used for all cost collection, analysis and forecasting by the OR;
- A budget transfer authorization was used by OPG to manage funds transfers between work packages and to control the use of contingency;
- Project costs were recorded when committed – as opposed to actually spent - wherever appropriate as, for example, when a work package was to be executed via a contract;
- Actual vs. estimated/budgeted costs were tracked at Level 3 – and sometimes Level 4 - of the CBS; and
- Future cost flows and final costs were reforecast monthly. After the ADBA was in place, the OR did a reforecast of the Project final cost, using the detailed estimating model, every quarter.

Under the original DBA fixed price contract the Contractor’s actual costs were not available to the OR and OPG. Payments were made monthly based on completion percentages against a cost breakdown included in the contract. Actual progress against these payment milestones was verified by the OR’s construction site staff prior to authorizing payment of the invoice. Because the Contractor’s real costs were unknown

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29 The ADBA did not change the method by which the above ground, subcontractor work was handled, i.e. the costs of the intake and outlet work remained essentially fixed price per the original subcontract amounts.

30 OR Project Controls staff believed that this gave much more transparency into cost controls than the use of commercially available project management software packages.

31 If one work package was forecast to be underspent, surplus funds could be transferred to another work package that was forecast to be over the original budget. This avoided the need to route funds transfers through contingency.
prior to the ADBA, the OR was unable to calculate a Cost Performance Index (CPI) for the Project.

Although it was originally intended to transfer OR cost data automatically into the OPG SAP® system, this idea was abandoned when it was deemed to be too difficult to do so; cost data was therefore transferred manually from the OR to OPG throughout the Project.

**ADBA Cost Control**

The Amended Design-Build Agreement was an “open book” contract in which all Strabag costs were collected in QuickBooks® and were available electronically for inspection by OPG and the OR. Under the ADBA, costs were categorized as either Allowed or Disallowed. A Disallowed Cost was any cost from a specific list in the ADBA, including such items as costs to vacate liens filed by the Contractor and subcontractors, non-project head office costs, income taxes and withholding taxes. Disallowed Costs also included the cost to repair nonconformances that had been identified by the OR but not reported by the Contractor. In total there were 19 categories of Disallowed Costs. The contract included a formal method for OPG to advise the Contractor that a cost would be disallowed.

Any Contractor planned expenditures for goods or services of more than $100,000 required prior OPG authorization through a formal approval process.

OPG paid all of the Contractor’s actual, Allowed Costs on a monthly basis. Contractor draft invoices were first subject to a cost audit by Durward, Jones, Barkwell, a third party auditor retained by OPG, prior to being formally submitted for payment approval. As well as ensuring that the work progress had been accurately reported by the Contractor, the OR would also do certain reasonableness tests on cost items, based on its own records and observations, and check to ensure that no Disallowed Costs were being included in Contractor invoices before recommending payment.

Because both a detailed Contractor estimate and the actual costs of work performed under the ADBA were available after mid-2009, the OR was able to calculate and report a Cost Performance Index (CPI) in addition to the SPI for the latter half of the Project.

**4.5.3 Progress Reporting**

Throughout the Project, work progress including TBM mining rates, delays, geology, and overbreak was monitored and reported to OPG on a daily basis by the OR construction management staff at the work site. The OR also prepared weekly status updates for

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32 If the Contractor identified and reported a nonconformance, the cost to rectify it was an Allowed Cost.

33 CPI = Earned Value/Actual Cost. It is a measure of cost efficiency and a CPI ≥ 1 indicates that a project is on track to finish within the approved estimate.
OGP that included a 2-week projection of activities under the ADBA as well as cost and schedule status and current safety, environmental or other issues and concerns for the Project.

In addition to daily and weekly progress and status reports, the OR prepared and submitted a comprehensive monthly Project report that included information concerning:

- Tunnel work progress and schedule status;
- Project costs;
- SPI and CPI;
- Safety;
- Security;
- Environmental performance;
- Permits and approvals status;
- Design progress;
- Project issues and associated actions;
- Claims;
- Stakeholder communication and issues;
- Risk management; and
- Quality (Non-conformance information).

These monthly reports also included information supplied by OGP giving a summary of the status of the Ontario Power GS and Toronto Power GS reversion subprojects until this work was completed in August 2007.

4.5.4 Change Management
A formal change management process was used to ensure that neither the physical characteristics of the facility nor the Project cost, schedule or risk profile would be modified without a thorough review and formal approval of any proposed change. The change and claims management processes were outlined in the contract and a more detailed procedure, with accompanying forms, was documented in the OR’s Policies and Procedures Manual for the Project. The change control process involved three steps:

4.5.4.1 Change initiation
A proposal for a Project change could be initiated through either a Contractor-prepared Project Change Notice (PCN) or through a draft Project Change Directive (PCD) prepared by the OR/OPG. These would include:

- A description of the proposed change;
- The reason for the proposed change;
• The impact of the change on aspects of the Project such as form, function, reliability and cost effectiveness;
• The consequences of not making the change;
• Cost impact of the change; and
• Schedule impact of the change.

4.5.4.2 Change Control Board Review
Proposed changes were reviewed by a Change Control Board (CCB) which consisted of:
• OR Project Manager (Chairperson);
• OPG Project Director;
• OPG Director of Finance \(^{34}\); and
• OR Project Controls Manager.

Other specialists could also be invited as participants upon request of the chairperson. A representative from OPG Law acted as an advisor to the CCB after initiation of the ADBA.

CCB meetings would be convened as necessary. A member of the OR staff would generally present the proposed change to the CCB. After reviewing the proposed change, the CCB would vote either to approve it or to reject it, with reasons. If the proposal was approved the CCB Chairman would prepare a recommendation to the Project Sponsor (Vice President, Hydroelectric Development). The Sponsor could then sign back the recommendation as approved, request a modification, or reject it with reasons and a path forward.

4.5.4.3 Project Change Directive
Approved changes were formalized and transmitted through a Project Change Directive, prepared by the OR Project Controls Manager, that would instruct the Contractor to proceed with the change. The main tunnel contract included the required format for documenting PCDs. As with the PCN or draft PCD, the final PCD would include information concerning:
• The change to the scope of the contract or purchase order, described in sufficient detail as to be “indisputable”;
• Adjustment to the Project cost and schedule (Target Cost and Target Schedule in the case of the ADBA); and
• Changes to any other terms or conditions of the contract. Such changes required sign-off by OPG Law Division.

PCDs were approved by OPG at the appropriate level of OAR signing authority.

\(^{34}\) Prior to the ADBA, the other OPG member was the Project Sponsor.
After implementation of the ADBA, if a PCD did not involve a “material” (i.e. cost of more than $100,000) increase in the work or a change in the target cost or target schedule, it was considered a “deemed amendment” \(^{35}\) to the ADBA and required only signatures by OPG and the Contractor to be implemented. Any other approved PCDs required the additional step of issuing a formal amendment to the contract before being implemented. Amendments to the ADBA required the signature of the President/CEO (or delegate) of OPG as well as Contractor agreement.

The OR tracked the status of, and maintained logs of, PCNs and PCDs and also maintained a conformed copy of the Design-Build Agreement with approved changes.

4.5.4.4 Claims

Claims from the Contractor would generally arise where the Contractor was seeking cost and/or schedule relief for encountering unexpected conditions for the work. Claims could also be made if the Contractor objected to a Project Change Directive from OPG. The initial notice of a claim had to be submitted within a prescribed time frame after the occurrence leading to the claim. The formal claim was then more formally documented via the PCN process.

An attempt would first be made to negotiate the claim with the Contractor. The Project Manager and other relevant OR staff would review the statement of claim, hold discussions or non-binding negotiations with the Contractor, and prepare a written opinion on the merits and amount of the claim for review. If a resolution was agreed upon, the Project Manager would convene a CCB meeting and, following the CCB procedure described above, would transmit a decision on the claim to the Contractor. Under the ADBA if the Contractor disagreed with the decision, it could issue a Notice of Informal Resolution to have the claim referred to a Steering Committee consisting of one senior representative each of the Contractor and OPG. If unable to reach agreement the Steering Committee could refer the claim to an expert or experts for a recommendation or, failing agreement at that stage, the claim would go to arbitration.

4.6 Risk Management

Risk management for the Project followed relevant governance as well as generally accepted project risk management practices that included:

- Risk management planning;
- Risk identification and assessment (both qualitative and quantitative assessments were done);
- Risk response planning;

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\(^{35}\) A slightly different definition of “deemed amendments” was actually introduced to the original DBA in September 2008 via Amendment 5. Although they could be implemented through a PCD, “deemed” amendments were also often incorporated into the next formal Amendments to the ADBA.
• Risk monitoring and control; and
• Risk reporting.

4.6.1 Risk Management Plan
The OR prepared and issued Revision 0 of the Project Risk Management Plan in October 2006. The OR also prepared subsequent plan revisions (R1 – May 2007, R2 – May 2008, and R3 – August 2008). Revision 4 was prepared by OPG and issued in April 2012. An earlier version of the plan reflected a combination of OPG and HMM approaches to risk management. Revision 4 was prepared in accordance with the corporate governance standard OPG-STD-0062 in effect at the time.

The risk management plans outlined the overall process steps to be followed, responsibilities of the various parties, and the methods and tools - such as the format of risk registers - that would be applied to the process.

4.6.2 Risk Identification and Assessment
During Phase 1 (Planning and Procurement) of the Project, OPG retained URS Canada Inc. to facilitate risk management activities that included risk identification workshops, preparation of initial risk registers, and both qualitative and quantitative risk assessments.

The URS methodology incorporated relevant elements of the recently produced International Tunnelling Insurance Group draft "Code of Practice for Risk Management of Tunnel Works" (the "Code")36.

4.6.2.1 Qualitative Assessment
Four facilitated qualitative risk workshops, with subject matter experts from OPG, HMM and URS were held during the pre-tender period37. To aid in identifying and assessing the risks during these workshops, the URS risk assessment process grouped the risks into eight “hazard”38 categories. Each workshop focused on a subset of the eight categories.

The risk assessment process used in the workshops included the following steps:
• Each hazard was assigned a probability between 1 (very low) and 5 (very high) by the expert panel. The OPG operational risk assessment criteria in effect at the time were used to numerically rate the impact – also on a 1 to 5 scale - of each

36 Section 6.4.2 of the Code states that “A Risk Assessment shall be carried out and a Risk Register shall be prepared for the preferred project option (or options). This Risk Register should include the perceived hazards and associated risks for the preferred project option (or options) and indicate potential mitigating measures with comprehensive explanations for their basis, based on the studies carried out during the Project Development Stage. This Risk Register shall be included within the information provided to tenderers during the Construction Contract Procurement Stage.”
37 Workshops were held on December 9 and December 23, 2004, and January 14 and February 4, 2005.
38 Under the URS methodology a “hazard” is a situation that, if it occurs, brings about a negative impact on achieving project objectives. Other methodologies may refer to this as a “risk event”.

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hazard on the following Corporate and Project objectives: financial, schedule, corporate reputation, regulatory/legal, health and safety, and environmental.

- Using the product of the probability rating and the highest impact rating, an overall risk level was then calculated for each hazard using a standard 5 X 5 risk heat map. The heat map was used to categorize hazards as being of “low”, “medium” or “high” risk. It should be noted that any hazard that had an impact level of 5 on any of the objectives, regardless of probability, was categorized as a “high” risk to reflect the importance of low probability but high consequence events.

The above steps were done for both the inherent risk and the residual risk. The inherent risk assessment assumed that no particular control measures for the hazard were in place, while the residual risk assessment was based on control measures that had already been taken at the time of the workshop. The following table shows the number of hazards identified in each category as well as the number that were assessed as being of “high” risk.

<table>
<thead>
<tr>
<th>Hazard Category</th>
<th>Total Hazards Identified</th>
<th>High Risk – Before Mitigation Measures</th>
<th>High Risk – After Mitigation Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Approvals and permitting</td>
<td>11</td>
<td>6</td>
<td>5</td>
</tr>
<tr>
<td>Stakeholder issues</td>
<td>2</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Planning and conceptual design</td>
<td>9</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Financial and contractual</td>
<td>17</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Logistics and access</td>
<td>5</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Final design and construction</td>
<td>17</td>
<td>8</td>
<td>6</td>
</tr>
<tr>
<td>Environmental issues</td>
<td>11</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Safety and security</td>
<td>14</td>
<td>5</td>
<td>1</td>
</tr>
<tr>
<td>Total</td>
<td>86</td>
<td>29</td>
<td>20</td>
</tr>
</tbody>
</table>

Of all the hazards, only eleven that evaluated as “high” risks, before mitigation were considered to have a probability rating of 4 or 5 (i.e. likely or probable.) Sixteen hazards with low probabilities were still considered “high” risks due to having an evaluated impact of 5 on one or more of the corporate objectives.

Results of the URS qualitative analysis were documented in the “Niagara Tunnel Project Qualitative Risk Assessment Report”, dated February 24, 2005.

As part of their proposals the tunnel proponents were required to prepare their own independent risk assessments and were required to submit the results of these
assessments as summary risk registers, which were considered by OPG during proposal evaluation.

4.6.2.2 Quantitative Assessment

At two of the URS workshops, the expert panel members were also asked to further quantify the consequences of selected hazards\(^{39}\) in terms of the possible range of cost and schedule delay impacts. The impact ranges were given as 3-point (low, mean and high) estimates that were input as parameters into probability functions to be used in a Monte Carlo analysis of the Project cost and schedule. The Monte Carlo analysis then produced probability distributions of Project cost and duration that could be used to establish recommended contingency amounts that would reflect a particular level of confidence in the estimate and the scheduled completion date.

Based on the URS analysis, the initial cost and schedule probability distributions suggested the following contingencies:

| Table 4.3 |
|-----------------|-----------------|
|                  | Cost Contingency | Schedule Contingency |
| For 80% probability of non-exceedance | $20 million | 23 weeks |
| For 90% probability of non-exceedance | $33 million | 30 weeks |


The initial risk analysis was conducted before responses to the RFP were received from the design-build proponents. Because of this, the analysis considered only “generic” risks without taking into account possible differences in design, construction methods, commercial terms or other aspects of the proponents’ proposals that could lead to variations in the types and consequences of hazards. Therefore, it was recognized at the time this analysis was done that further assessment of the risks, and the necessary contingencies, would have to be carried out once the proposals were received and evaluated.

After the design-build proposals were received and analyzed in May-June 2005, OPG updated the quantitative analysis model that had been developed by URS, with the intent of:

- Confirming the overall assumptions;
- Confirming estimated numerical inputs;

\(^{39}\) Not every hazard was included. URS used a number of criteria to select which hazards would be included in the quantitative analysis, e.g.: “the risk factor (hazard) should not be associated with a condition or event whose chance of occurrence is remote”
• Identifying additional hazards and removing hazards that were no longer relevant; and

• Adapting the assessment to reflect differences among the proposals.

Expert panel workshops were held on June 29 and July 12, 2005 to identify necessary updates to the assessment. Participants in these workshops were mostly the same individuals who had contributed to the earlier assessment facilitated by URS and represented engineering, legal, commercial and other areas of expertise.

Overall assumptions and estimates that were used for the re-assessment included:

• For all hazards, only direct cost impacts (e.g. incremental materials and labour to correct a problem) were considered. Costs of the Contractor’s and OPG’s “burn rate” during delays were excluded;

• Schedule delays were estimated in terms only of critical path impact; and

• The consequences of schedule delays were transformed into equivalent costs by multiplying delays by a “burn rate” of $275,000 per day, based on:

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contractor’s labour</td>
<td>$225,000</td>
</tr>
<tr>
<td>Stand-by cost of equipment</td>
<td>$25,000</td>
</tr>
<tr>
<td>OR cost</td>
<td>$20,000</td>
</tr>
<tr>
<td>OPG cost</td>
<td>$5,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$275,000</strong></td>
</tr>
</tbody>
</table>

Using the quantitative risk register from the URS report as a reference, all hazards were reviewed and their probabilities of occurrence, as well as cost and schedule consequences, were re-evaluated for each proposal. Some of the hazards were no longer relevant and were removed from the register. Five new hazards were added to the register based on information in the Design-Build proposals (e.g. more detail on geotechnical risks). Differences among the three proposals were also reviewed, which led to different numerical estimates for certain hazards as applied to each proposal. For example, the risk of water inflows into the tunnel depended on the tunnel alignment, type of tunnel boring machine, and the liner design, which varied among the proposals.

In the updated analysis, the top two contributors to potential cost increases were found to be: 1) “Dispute Review Board Interpretation of Agreement unfavourable” and 2) “DSC [Differing Subsurface Conditions] claim due to rock strength.” These same two factors, in reverse order, were also identified as the top two contributors to potential schedule delays for which OPG, rather than the Contractor, would be responsible.

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40 Burn rate is essentially the fixed cost of maintaining staff, facilities and equipment in place on the project during a given time period.
Based on the updated quantitative assessment for the selected Design-Build proposal, OPG’s cost contingency for the tunnel contract was revised upward to $96 million to meet a 90% confidence level. The schedule contingency was set at 36 weeks, based on the estimated OPG-accountable delay, also at 90% confidence. The total Project contingency at release ($112 million) included the $96 million for the tunnel contract, as well as additional contingencies for other Project elements.

4.6.3 Risk Registers

The risks identified during the URS-led analysis, and later updated by OPG, were documented in an “OPG Risk Register”, created in Excel®, which included risk description and consequence information, probability and impact ratings, and mitigation plans.

As a condition of providing Builder’s All Risk insurance coverage for the Project, the underwriters required that significant portions of the International Tunnelling Insurance Group "Code of Practice for Risk Management of Tunnel Works" be adopted. As a result, OPG and the Contractor were required to share details of their respective risk assessments and to systematically coordinate construction phase risk management efforts. A second risk register, known as the “Construction Risk Register” was created to capture those OPG and Contractor-identified risks that were not deemed to be commercially sensitive or confidential by the respective parties; in general these risks were related to the technical aspects of project execution. This risk register also showed which entity (OPG or the Contractor) was the risk “owner”, responsible for management of the risk.

For OPG’s internal management reporting purposes a third risk list – the “Top Ten” list - was created to summarize information regarding the most critical risks from the OPG Risk Register and the Construction Risk Register. Neither the OPG Risk Register nor the Top Ten list was shared with the Contractor.

Following the formation of the Amended Design-Build Agreement in 2009, the OPG Risk Register was modified, by combining some of the individual hazards from the original registers into broader risk event categories, and also by including some of the risks from the Construction Risk Register, to become the “NTP Key Risk Register”. This risk register no longer showed the inherent (before mitigation) risk qualitative data, but only included the residual (after mitigation) risk data. Risk champions or owners were assigned to each risk. A subset of the Key Risk Register data was also created as the “Key Risk Register Summary.”

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41 Only delays for which OPG would be accountable were considered since the contract included liquidated damages for contractor-caused delays.

42 Through the combination process, some of the originally identified hazards became risk causes for the higher-level risk events in the new register.
OPG also developed, and periodically reviewed a risk register, showing risks associated with the relationship with the Owner’s Representative. The most serious risks identified were associated with continuity of OR key Project personnel, in particular the Project Manager. During the early portion of the ADBA, there was also an initial concern regarding the adequacy of OR processes for overseeing Contractor progress and payments under the new agreement.

4.6.4 Risk Allocation
As part of risk management planning it was recognized that specific risks should be assigned to the organization (OPG or the Contractor) that could best manage that risk. The Construction Risk Register identified which of the two parties would “own” each risk and therefore take responsibility for control or mitigation measures.

OPG originally assumed part of the risk of Differing Subsurface Conditions, through the incorporation of the agreed Geotechnical Baseline Report C in the contract documentation. A contingency amount was included in the approved Project budget to cover possible costs associated with this risk. The ADBA more fully defined the way the DSC risk events such as excessive overbreak would be measured and the cost differences that would be allocated to each one.

In general, with the exception of the risk of property acquisition delays, which was OPG’s, most other risks associated with the design and construction of the work, were allocated to the Contractor. The Contractor was also allocated the risk of schedule delays related to obtaining permits and approvals.

4.6.5 Risk Monitoring
The Construction Risk Register was reviewed and updated approximately every six weeks throughout the entire Project. The OPG Risk Register was initially internally reviewed with the OR every quarter. Following the conversion to the Key Risk Register in 2009 the risk review frequency became monthly, with the various designated “risk champions” reviewing their assigned risks on a rotational basis (i.e. not all risks were reviewed every month).

The purpose of the risk reviews was to update the risk registers to reflect the progress of the work, including mitigation activities, and to capture any changes in the risk profile, including new risks or risks that may have arisen because of mitigation measures and changes in the work processes or as-found conditions.

4.6.6 Insurance Coverage
As part of the design and construction risk transfer strategy, OPG obtained insurance coverage for Wrap-Up Liability, Builders’ All Risk and Marine Cargo Coverage. The OR maintained Errors and Omissions Insurance. The Contractor provided Errors and Omissions Insurance, Motor Vehicle Liability Insurance, Construction Equipment Insurance, and Workers Compensation coverage.
To mitigate the financial risk to OPG, the DBA required Strabag to provide a letter of credit for $70 million as well as parental indemnities guaranteeing its performance and indemnifying OPG for any damages resulting from a breach by Strabag. Strabag also was required to provide a maintenance bond of 10% of the contract price to remain in force until the end of the warranty period, which was one year following the date of Substantial Completion. OPG and Strabag subsequently agreed to maintain the letter of credit for the duration of the warranty period in lieu of the maintenance bond.

As a condition of the Builders All Risk insurance agreement, OPG was required to periodically provide Project risk information and updates to the insurers.

4.6.7 Additional Risk Assessment for ADBA

As outlined in section 3.5.3, a risk assessment was conducted in 2009 by OPG Risk Services to support the revised estimate and schedule for the Amended Design-Build Agreement and the Superseding Business Case. Two additional risk assessments were conducted later as described below.

In May 2010, a quantitative (Monte Carlo) analysis was carried out by OPG Project Risk Management (PRM) to ascertain whether the then-current schedule for the intake end cofferdam removal and outlet end dewatering structure and rock plug removal was still feasible. The analysis concluded that the dates were still valid.

A second detailed quantitative review of the Project risks was conducted in March-April 2011 to re-examine the probabilities of achieving the target schedule and cost outcomes. This analysis included two workshops facilitated by PRM. The first workshop dealt with schedule uncertainty. The OPG/OR Project Team and the Contractor’s Subject Matter Experts developed three-point (pessimistic, most likely, and optimistic) estimates for each of the major remaining scheduled activities. These estimates were input into Pertmaster®, a software package used to run a Monte Carlo simulation of the schedule to establish a completion date probability function curve.

The second risk workshop was held to review the adequacy of the cost contingency. The OPG/OR NTP Project Team worked with PRM to identify the remaining probability of occurrence and three-point schedule and cost impact estimates for fifteen of the significant Project risks from the Key Risk Plan summary. Schedule impacts were converted to costs using “burn rates” calculated by the Project Team and OPG Finance.

From the analysis, it was concluded at the time that:

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43 Some of the key risks from the original risk plan were excluded because of the current state of progress of the project (e.g. tunnel mining was almost complete at the time).
There was very high confidence that the tunnel would be in-service by July 31, 2013, well in advance of the December 2013 target date approved by the Board in the Superseding BCS;

There was low confidence that the tunnel would be in-service by the ADBA Target Schedule date of June 15, 2013 (subject to adjustment due to excess overbreak);

There was very high confidence that the final Project cost would be below the Superseding BCS approved estimate of $1,600 million; and

There was medium confidence that no more than half of the $164.4 million Project contingency would be required.

As outlined in Section 5.3 (Schedule Outcomes) Strabag was able to advance the in-service date, to well before the Target Date, by changing the approach to removal of the tunnel lining equipment to allow earlier watering-up and cofferdam removal at the intake end.

4.7 Health and Safety Management

For most of the Project, the DBA/ADBA established the Contractor as the “Constructor” under the OHSA Construction Regulations. This relieved OPG in its “Owner Only” role of the responsibility – and risk – for health and safety management of the Contractor’s work force.

The Contractor was required to submit a Project Specific Site Safety, Security, Public Safety and Emergency Response Plan (SSSP), both as a draft with the proposal and as a submission after contract award, outlining how they would fulfill their obligations as Constructor to manage Project health and safety. The SSSP submitted by Strabag was actually prepared by its major civil subcontractor, Dufferin Construction. OPG and the OR reviewed the SSSP for acceptability.

The Contractor was required to report all safety related incidents to the OR who would in turn notify the OPG Project Director. The Contractor was responsible for investigating, reporting, and implementing remedial actions.

The OR was tasked with overseeing the Contractor’s compliance to the SSSP, as well as relevant regulations, through observations and periodic audits. The OR Health and Safety Advisor made site visits on a weekly basis. These visits typically reviewed:

- Use of established safety procedures within the SSSP;
- Development and use of Job Safety Analyses (JSAs)/pre-job briefings/JSIs;
- Inspection program;
- Incident management; and
- Housekeeping/Workplace Hazardous Materials Information System (WHMIS) program.
Any OR observations of hazards or noncompliance were communicated to the Contractor at regular weekly meetings. For more serious issues, a Project Safety Compliance Observation Form was given to the Contractor with a request for a response although, in an Owner Only role, OPG and the OR could not directly instruct the Contractor to take any specific measures regarding the safety of its workers.

OPG was required to operate control gates at the INCW for ice, flow and water level management, which would affect in-water work at the intake end and possibly constrain the Contractor’s construction activities requiring access to and along the INCW structure. Without full control over this work area the Contractor could not, under the Construction Regulations, be the “Constructor” during some periods of the Project. Therefore, early in the Project, OPG applied for and received approval from the Ministry of Labour to designate a discrete portion of the Project around the INCW as the separate “INCW Part Project” for which OPG would be the Constructor during two stages\(^{44}\) of the intake end work. For the Part Project the OR acted on OPG’s behalf to manage on-site safety supervision. This included:

- Conducting its own independent pre-job hazard assessment of the Part Project for use as a reference when reviewing the Contractor’s hazard assessments;
- Reviewing the Contractor’s Site Specific Safety Plan and JSAs;
- Ensuring that necessary safety training was delivered either by the Contractor or by OPG personnel;
- Monitoring safety performance through regular inspections;
- Ensuring the Contractor met requirements for incident reporting, investigation and follow up;
- Managing the Project safety audit program, and monitoring corrective actions;
- Attending the Contractor’s toolbox and pre-job briefing meetings;
- Participating in the Joint Health and Safety Committee; and
- Holding work protection for the Contractor.

For the Part Project the Contractor was required to meet OPG’s health and safety policies and requirements and, as Constructor, OPG through the OR could provide direction to the Contractor in health and safety matters.

OPG provided the necessary work protection training for OR and Contractor staff.

\(^{44}\) Designation of a “part project” is allowed under the regulations. The Part Project was in effect at the intake end during Stage 1 (construction of the cofferdam and in-river replacement of the ice accelerating wall) and Stage 3 (removal of the cofferdam). For Stage 2 when work was being carried out within the cofferdam, the Contractor was the Constructor since OPG’s operations would not affect worker safety in this area.
4.8 Environmental Management

As the Owner of the NTP, Ontario Power Generation was ultimately accountable for complying with the conditions of the Environmental Approval and for obtaining the necessary environmental permits and approvals from government and municipal agencies. Some required approvals had already been received during the earlier (1990s) attempt to start the Project. Starting in the Planning and Procurement Phase, the OR was tasked with initiating some permit applications in order to ensure they would be available when required for the start of construction. However, through the DBA/ADBA, the Contractor was assigned responsibility for completing or obtaining many of the remaining necessary permits and approvals directly related to construction activities. Approval applications and associated documentation were provided to the OR and OPG for review prior to submission to the appropriate agency.

Some of the main environmental concerns that had to be addressed, either because of EA conditions or to meet regulatory requirements, included:

- Management and disposal/storage of excavated materials (e.g. through their use in brick manufacturing or as aggregate);
- Management of contaminants from excavated shale materials containing naturally-occurring BTEX (Benzene, Toluene, Ethyl benzene and Xylene);
- Emissions to air, including equipment and vehicle emissions as well as dust from the transport of material removed from the tunnel, from vehicle movement, or from blasting;
- Emissions to water, including run-off, silt or sediment from construction activities as well as potential spills of fuel, lubricants or hydraulic fluid from construction equipment;
- Management of hazardous and non-hazardous waste;
- Noise from construction activities;
- Impacts of blasting on fish as well as structures in the vicinity of the Project;
- Impacts on groundwater along the tunnel route;
- Impacts on local vegetation and wildlife (e.g. bird nesting);
- Impacts on local residents, tourist attractions and businesses; and
- Impacts on local roads and transportation.

Minimum requirements for the management of some of these issues were included in the contract as part of the Owner’s Mandatory Requirements and in other sections of the contract. The Contractor was required to develop a comprehensive Environmental Management Plan that addressed permitting and approval processes as well as

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45 For example, an exemption from the Navigable Waters Protection Act, DFO authorization of “destruction of fish by means other than fishing”.

46 The Strabag Environmental Management Plan was prepared by its subcontractor Morrison Hershfield. A draft plan was submitted with the original proposal and a final plan was submitted after contract award.
providing more detailed plans for the management of environmental concerns. The Contractor also prepared an Environmental Compliance Plan that described how tools such as environmental audits, risk management analysis, quality assurance/quality control, inspection, monitoring and training would be used to ensure compliance with the contract and legal and regulatory requirements.

The role of the OR was to assist OPG by developing the necessary documentation for applications for permits and approvals as well as to provide oversight and periodic audit of the Contractor’s environmental management and reporting.

4.9 Quality Management

4.9.1 General
Although no overall Quality Plan was produced for the Project, the required elements of project quality assurance and quality control were embedded in a number of Project documents. The original Design-Build and Amended Design-Build Agreements incorporated the Contractor’s ISO 9001 compliant Quality Manual and Quality Plans and Procedures. The overall intent was that this QA system, audited for compliance by the OR, would form the basis for tunnel Project quality management.

The OR did a number of formal quality audits of Strabag and its subcontractors. In addition, one Project level audit done by OPG Internal Audit after implementation of the ADBA examined OPG’s QA oversight.

OR oversight of the Contractor’s quality assurance and quality control process was described in the Project Execution Plan sections and supporting Project procedures for:

- Engineering Management;
- Construction Oversight, Installation and Commissioning;
- Project Controls and Reporting (change management sections); and
- Records Management.

The OR procedures were supported and documented by the use of numerous forms to capture records of the observations of the Contractor’s work and communications between the OR, the Contractor and OPG.

The OR held periodic (several times per year) meetings with the Contractor to review QA/QC issues and actions. OPG also received quality updates from the OR during the regular weekly meetings.

4.9.2 Supplier Quality Assurance
In addition to Strabag, a number of subcontractors also maintained ISO 9001 compliant Quality Assurance programs throughout the Project. Some of these subcontractors were:

- ILF Beratende Ingenieure ZT Gesellschaft mbH (design subcontractor);
• Dufferin Construction Inc.;
• Bermingham Construction Ltd.;
• McNally Construction Inc.;
• Allied Fabricators Inc.; and
• Geo Foundations Contractors Inc.

The Contractor was responsible for conducting factory testing on various equipment and components of the work such as the TBM and associated backup equipment, and the intake and outlet gates. The OR and OPG were notified in advance of factory testing to allow for verification which was a condition for payment certification.

4.9.3 Design Quality
The Contractor prepared a comprehensive Design Quality Plan that was divided into a preparative phase, a preliminary design phase, and a detailed design phase. The plan covered all aspects of the design such as the cofferdam, intake and outlet civil works and structures, the diversion tunnel, mechanical and electrical works, dewatering system. For each item it listed the design activities, quality requirements and quality controls as well as responsibilities for QA verification.

Required Contractor engineering submittals to the OR and OPG included:
• Design basis documents;
• Detailed construction drawings;
• Detailed construction and material specifications;
• Checked engineering analysis and design calculations;
• Minutes from the Contractor’s design review meetings;
• Construction methods;
• Environmental protection procedures;
• Quality assurance/quality control plans and procedures;
• Specific method statements;
• As built construction drawings and specifications; and
• Checked design calculations for revisions to the 100% construction documents.

 Appropriately qualified OR professional engineering staff reviewed the Contractor submittals to verify that they were in general conformance with applicable laws, the Owner’s Mandatory Requirements, the terms of the DBA/ADBA, the Contractor’s design basis documents, and other related submittals. In some cases, OPG engineering staff would also review and comment on Contractor submittals. Submittals could be accepted, or returned for revision with or without a requirement for resubmittal. Acceptance of a submittal by the OR did not constitute “approval” and did not relieve
the Contractor of its contractual obligations regarding design, fabrication, construction, suitability for purpose, or warranties under the DBA/ADBA.

4.9.4 Construction Quality
The Contractor developed, and submitted for OR review, individual method statements and quality plans describing the activities, quality requirements, and the QA/QC responsibilities for each major aspect of the tunnel such as tunnel excavation and support, shotcreting, waterproofing system, concrete work and grouting.

The OR closely monitored Contractor activities during all construction shifts. OR construction monitors used detailed forms and checklists to record progress and audit operations and final product quality against the designs and methods. Contractor activities dealing with permanent works were checked before “covering” (e.g., prior to concrete installation, backfilling, etc.) to confirm that the Contractor had performed the necessary quality control to ensure compliance. TBM tunneling and final concrete liner monitoring was done on a full-time basis during every shift. Some activities such as profile restoration were monitored on a part-time basis by OR staff who looked after a number of concurrent tunnel operations. One critical item monitored was crown overbreak, which was measured on a frequent basis because the ADBA allowed for adjustment of the contract schedule and target cost per the Major Risk Table in the event that actual overbreak values exceeded the baseline overbreak amount.

4.9.5 Nonconformances
If work was found not to conform to the contract specifications or the Contractor’s Quality Assurance/Quality Control Plan, a Non-Conformance Notice (NCN) could be issued by either the Contractor or the OR. If the nonconformance was found by the OR rather than the Contractor a Disallowance Advisory could be prepared, as outlined in the ADBA, advising the Contractor that future non-conformance would result in a Disallowed Cost. NCNs were logged by the OR and tracked through a Nonconformance Register until their disposition was complete.

Appendix B is a flowchart showing the nonconformance management process.

4.10 Communication

4.10.1 Stakeholder Engagement and Communications
The location, scale and duration of the Niagara Tunnel Project meant that there would be significant impacts on the local community, including tourism, transportation, other municipal services such as water or sewer and employment. It was recognized from the outset that maintaining good relationships with the community would be critical, not only for the success of the NTP, but also to ensure that the existing community support for the Niagara Plant Group and the positive public perception of OPG were not compromised.
In addition to Federal and Provincial regulatory agencies, some of the key external stakeholders for the NTP included:

- Niagara Parks Commission;
- Niagara Escarpment Commission;
- Niagara Peninsula Conservation Authority;
- Regional Municipality of Niagara;
- City of Niagara Falls;
- Town of Niagara-on-the-Lake;
- Niagara Falls Tourism; and
- Local suppliers, contractors, building trades.

In 1993, Ontario Hydro, as part of its commitments under the EA submission, had negotiated a Community Impact Agreement (CIA) with the local municipalities to mitigate the predicted impacts of the construction of the originally intended Niagara River Hydroelectric Development (NRHD) on tourism, roads, water supply, and sewage treatment. Under the CIA the municipalities agreed to grant all necessary local construction permits for the Project. In exchange, Ontario Hydro was required to:

- Consider local planning requirements in developing the NRHD;
- Consult with the municipalities on an ongoing basis;
- Address complaints from residents impacted by the Project;
- Fund improvements and maintenance for roads impacted by construction traffic;
- Provide funds to mitigate impacts on sewage treatment facilities;
- Procure emergency services from the municipalities where practical and cost effective; and
- Seek opportunities to enhance local economic benefits including provisions for engagement of local contractors, suppliers and labour.

In August 2005, the CIA was amended to reflect the fact that the NRHD would be constructed in phases, the first of which would be the Niagara Tunnel Project. Payments of $7.87 million were made by OPG under the amended agreement in October 2005 after the Project received final approval.

A Community Liaison Committee was established to facilitate communication between OPG and local community officials. The Committee had representatives from the Regional Municipality of Niagara, City of Niagara Falls and Town of Niagara-On-The-Lake, as well as the Project Director, OR Project Manager and the Contractor. Liaison Committee meetings were held three or four times per year throughout the Project.

OPG took measures to ensure timely and accurate notification to the community of important Project events such as approvals, the start of construction, key Project
milestones, and Project completion. Public forums such as Open Houses were held as required. Processes were also put in place to communicate with local key stakeholders, interest groups, and the media to ensure that they were fully informed about the Project and could have any questions answered quickly. Community notifications included:

- Media releases and suggested information articles for community newspapers;
- Newsletters to key stakeholders and communities adjacent to construction activities; and
- A public website (www.niagarafrontier.com/tunnel.html) with frequently updated Project information.

Telephone and e-mail hotlines were set up for public complaints. These provided immediate acknowledgement of complaints and were monitored regularly to allow communication of a full response within pre-defined time limits. A protocol was established to direct all inquiries (and complaints) to appropriate NPG staff who would notify the OR for investigation and resolution of the issue with the Contractor. The Contractor was also required to inform the local construction industry of potential Project related employment and supplier opportunities, in line with the provisions of the CIA.

The OR or the Contractor would notify OPG Media Relations when fire, ambulance or police services were called to the Project site.

**4.10.2 Internal Communications**

An important objective of the Project was to “ensure sufficiently detailed reporting to the OPG Board of Directors and the Province of Ontario such that their confidence in OPG’s ability to execute large projects was maintained.”

The Project team communicated information to OPG senior management and the Board through the following mechanisms:

<table>
<thead>
<tr>
<th>Stakeholder</th>
<th>Information</th>
<th>Frequency</th>
<th>Media</th>
<th>Responsible</th>
</tr>
</thead>
</table>
| Phase 1 - Planning and Procurement | • High level performance metrics  
• Key external issues | Quarterly | Meeting and Presentation  
Meeting Handout  
Board Memo | Major Projects Committee/Project Sponsor |
| Board | | | | |
| Major Projects Committee | • High level performance metrics  
• Key external issues | Weekly (Memo)  
Quarterly | Memo  
Memo/Verbal/Presentation | Project Sponsor/Project Director |
<table>
<thead>
<tr>
<th>Phase 2 - Execution</th>
<th>Issues</th>
<th>Frequency</th>
<th>Report Type</th>
</tr>
</thead>
</table>
| OPG Board/Risk Oversight Committee (ROC) | • Written / verbal update at each Board/ROC meeting  
• Written Major Projects Status Report including cost and schedule metrics | Quarterly | Verbal Status Report |
| | | | Written Report |
| | | | SVP Hydro-Thermal Operations |
| OPG Enterprise Leadership Team | • Written report and verbal update  
• Written update at the OPG Key Results meeting  
• Monthly Report – Executive Summary distributed to ELT | Weekly  
Monthly | Verbal Status Report  
Written Report |
| | | | SVP Hydro-Thermal Operations  
Project Sponsor |
| SVP Hydro-Thermal Operations | • Cost, schedule, safety, environmental, key risks and quality reports  
• Issues/concerns and actions | Weekly | Verbal Status Report |
| | | | Project Sponsor |

The OPG Board remained actively involved in the Project throughout its duration, primarily through the activities of its Major Projects Committee (MPC), now called the Risk Oversight Committee (ROC).

The MPC:

- Reviewed and approved the proponent pre-qualification and RFP processes;
- Participated in the meetings used to determine which of the pre-qualified proponents would be invited to submit proposals;
- Provided oversight of the contract negotiations, and reviewed and accepted management’s selection of the preferred Contractor, Strabag;
- Reviewed the financial analysis underlying the business case for the Project and endorsed management’s recommendation, that the Project be approved, to the full OPG Board;
- Was actively involved in the review of OPG’s position before the DRB during the DSC contract dispute with Strabag;
• Reviewed the available alternatives with management and endorsed the approach of negotiating a revised contract with Strabag; and
• Recommended the Amended Design-Build Agreement to the full OPG Board for approval along with the Superseding Business Case supporting the new Project budget and schedule.

During the DSC dispute with Strabag OPG established a Contract Litigation Oversight Committee (CLOC) chaired by OPG’s Chief Financial Officer to provide independent oversight of OPG’s strategy for the dispute resolution and negotiations and to advise OPG senior management on the conduct of the dispute. The CLOC included external members Norman Inkster, former head of the RCMP, and Barry Leon, a lawyer who specialized in international litigation and arbitration. The CLOC continued to advise OPG during the ADBA negotiations with Strabag until an agreement was reached.

5 Project Outcomes

5.1 Safety
Key worker safety performance results were as follows:

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hours Worked (x1000)</td>
<td>28</td>
<td>545.8</td>
<td>699.1</td>
<td>712.9</td>
<td>900.1</td>
<td>1224.1</td>
<td>1290.8</td>
<td>1189.6</td>
<td>201.8</td>
</tr>
<tr>
<td>Lost Time Injuries</td>
<td>-</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>6</td>
<td>15</td>
<td>0</td>
</tr>
<tr>
<td>High MRPH Events</td>
<td>1</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Contractor “Serious” Events</td>
<td>-</td>
<td>5</td>
<td>7</td>
<td>11</td>
<td>16</td>
<td>16*</td>
<td>21**</td>
<td>12</td>
<td>-</td>
</tr>
<tr>
<td>Contractor “Major” Events</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>-</td>
</tr>
<tr>
<td>MOL orders</td>
<td>-</td>
<td>50</td>
<td>55</td>
<td>7</td>
<td>20</td>
<td>24</td>
<td>17</td>
<td>33</td>
<td>1</td>
</tr>
</tbody>
</table>

• * 4 of the “serious” events reported in 2010 relate to one incident where a compressor caught fire and 4 workers were exposed to smoke fighting the fire.
• ** 5 of the “serious” events reported in 2011 relate to a single situation where 5 workers experienced similar eye irritation from an unknown cause while installing rock bolts as part of the fall of ground repair.

Between 2005 and September 2013, 6.79 million construction hours were worked on site and 466 safety-related incidents/accidents were recorded. A total of 735 days were lost due to work-related injuries or illnesses. The overall reported LTI frequency (lost
time injuries per 200,000 hours worked) was 0.94. This was less than the construction industry average in Ontario that ranged between 1.58 in 2005 and 1.2 in 2009\(^{47}\).

The Contractor used its own incident categorization scheme and from the Health and Safety Incident Summary log it was not clear that the categorizations were consistently applied or directly comparable to the OPG incident categorizations. However, after implementation of the ADBA, the categorizations were clarified and from 2010 onward Contractor “Major” incidents can be considered roughly equivalent to the OPG “High MRPH” incident classification. There were a total of 13 reported work-related High MRPH or Contractor Major incidents, of which only one resulted in a lost time injury. Two Contractor Major incidents, one in September 2009 and the other in July 2011, were due to fall of ground collapses of part of the tunnel arch prior to installation of the final liner. There were no worker injuries directly related to these events.

There were a total of 207 Ministry of Labour Orders to Comply written over the course of the Project, of which 29 were for the INCW Part Project where OPG was the Constructor. During the period from 2007 through 2011 (for which MOL statistics are available) orders written for the NTP represented 25% of the total orders for all tunneling projects in Ontario.

OPG Internal Audit conducted a Health and Safety Audit of the INCW Part Project, where OPG was the Constructor, in September 2006 and found that the OPG/OR safety management processes were effective in managing the risks for that portion of the work. Two high MRPH incidents occurred in 2006 for the Part Project. Both involved in-water work by a subcontractor and neither resulted in a worker injury.

Since the Contractor was the Constructor for all but the Part Project, the OR had limited ability to influence the Contractor’s safety management practices. The mechanisms available included the weekly joint inspections, safety discussions at Project meetings, and mini safety audits conducted by the OR. Overall, safety management performance was acceptable.

The Project was successful in avoiding any injuries to members of the public. The only incident that had a potential for risk to non-Project personnel was the inadvertent release in the spring of 2006 of some crib timbers from the demolition of the original accelerating wall. These were transported downstream as far as the Maid of the Mist pool, and could have posed a danger to small craft. As soon as this was known, containment measures were put in place by the Contractor to prevent a recurrence.

5.2 Environment

The Contractor’s environmental management performance was judged by OPG to be relatively weak, particularly during the first years of the Project. An environmental audit conducted by OPG Internal Audit in mid 2007 cited a number of concerns including:

- A large number of spills and regulatory infractions;
- Inadequate follow up with corrective and preventive actions, leading to repeat occurrences;
- Failure of the Contractor to adhere to its own Environmental Management Plan, and to keep the plan up to date;
- Failure of the Contractor to report environmental incidents in a timely manner;
- Inexperienced environmental management staff in the Contractor’s organization (environmental management was initially provided by Morrison Hershfield, but later taken over directly by Strabag); and
- A need for the OR to improve its reporting on compliance monitoring activities.

Environmental events and regulatory infractions included:

- Many spills of hydraulic oil and other fluids;
- Inadequate treatment of drainage water from the tunneling activities, leading to releases of high levels of sediment into the PGS canal;
- Inadequate dust control measures, leading to complaints from local stakeholders; and
- Water treatment plant exceedances due to excess chlorine and chloride ion concentrations.

By late 2007 the Ministry of Environment was expressing serious concerns with the Contractor’s environmental management practices and was apparently even considering prosecution for ongoing non-compliance, although this did not occur. However, the MOE did significantly increase its on-site inspection activities, requiring OPG to provide funding to support the additional MOE costs for this.

The capability of OPG and the OR to have the Contractor make environmental stewardship beyond basic compliance a high priority was limited due to the Owner-only nature of the contract, which generally precluded giving specific direction to the Contractor. However, it appeared that the Contractor’s regulatory compliance improved somewhat following the OPG audit and MOE intervention of late 2007.

5.2.1 Reportable Spills

The following table shows the number of spills reported by the Contractor during the Project:

<table>
<thead>
<tr>
<th>Date</th>
<th>Spill Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016-12-22</td>
<td>Hydraulic Oil Spill</td>
<td>Spilled from tunneling activities, leading to releases of high levels of sediment into the PGS canal.</td>
</tr>
<tr>
<td>2016-12-23</td>
<td>Other Fluid Spill</td>
<td>Spilled from tunneling activities, leading to releases of high levels of sediment into the PGS canal.</td>
</tr>
<tr>
<td>2016-12-24</td>
<td>Hotel Industry Spill</td>
<td>Spilled from hotel industry operations, leading to releases of high levels of sediment into the PGS canal.</td>
</tr>
</tbody>
</table>
Table 5.2

<table>
<thead>
<tr>
<th>Year</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2006</td>
<td>0</td>
<td>5</td>
<td>9</td>
<td>3</td>
<td>17</td>
</tr>
<tr>
<td>2007</td>
<td>0</td>
<td>3</td>
<td>2</td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>2008</td>
<td>0</td>
<td>0</td>
<td>3</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>2009</td>
<td>0</td>
<td></td>
<td>10</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>2010</td>
<td>0</td>
<td></td>
<td>6</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>2011</td>
<td>0</td>
<td></td>
<td>10</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>2012 (Note 1)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>4</td>
</tr>
<tr>
<td>2013 (Note 1)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>TOTAL</td>
<td>8</td>
<td>40</td>
<td>4</td>
<td></td>
<td>61</td>
</tr>
</tbody>
</table>

Note 1: Project spills database does not show spill categories for 2012 and 2013. However from the spill report descriptions it appears that they would be Category “C”.

Of the total events reported, approximately 37% were due to spills or leaks of hydraulic fluid from construction equipment, 25% were due to discharges of suspended solids in the tunnel drainage effluent, and the remainder involved spills of fuels, shotcrete accelerator, or other miscellaneous fluids. With the exception of one sewage leakage incident (caused by a subcontractor cutting through a force main) in 2006, the remaining “B” category events all involved discharges of water with high levels of total suspended solids.

5.2.2 Regulatory Infractions
Regulatory infractions were, for the most part, incidents of noncompliance with a condition of one of the Certificates of Approval:

Table 5.3

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. Of Infractions</td>
<td>58</td>
<td>62</td>
<td>7</td>
<td>9</td>
<td>4</td>
<td>4</td>
<td>1</td>
<td>1</td>
<td>146</td>
</tr>
</tbody>
</table>

Of the total infractions reported, approximately 26% were due to water discharges exceeding the limits for Total Suspended Solids. An MOE Provincial Order was issued in December 2006 related to one of these events as well as for contravention of the CofA for Industrial Sewage Works. 22% of the other infractions were related to BTEX (mostly toluene) exceedances, and 20% were due to oil and grease discharges during one period in March and April of 2007. Other infractions related to excess total residual chlorine and excess chloride ion concentrations in the water treatment plant effluent.

Early in the tunnel mining process NPG staff reported to the OR that they were observing significant dust from the area where material being removed from the tunnel via the conveyor system was being dropped. There were complaints from the Niagara
Parks Commission as early as October 2006 that dust from the conveyor drop site was been carried off site to the adjacent Butterfly Conservatory and Botanical Gardens. Strabag initially attempted to address the problem by installing a sprinkler system at the conveyor transfer points and also installed dust-monitoring instrumentation at the affected sites. The dust problem persisted and eventually led to an MOE Provincial Order being issued on September 20, 2007 that required Strabag to take “all reasonable steps” to control dust emissions, to observe wind speeds, warn of possible off-site dust events, and maintain a log of events. Strabag installed a dust containment structure around the conveyor drop area, and took other measures to monitor and report on dust emissions. The containment structure reduced fugitive dust to an acceptable level.

In January 2009 the Niagara Parks Commission advised OPG that it was claiming damages for past and future impacts of the dust emissions on its property. OPG and the Contractor settled the claim with NPC in August 2011 for actual costs.
5.3 Schedule

As described earlier, the Project milestone dates planned in 2005 were significantly modified in 2009 as part of the Amended Design-Build Agreement. The following table summarizes the key planned, modified and actual Project dates.

<table>
<thead>
<tr>
<th>Major Activity</th>
<th>Original Target Date</th>
<th>Target Date (ADBA)</th>
<th>Revised Target Date (ADBA)</th>
<th>Actual Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>TBM Mining Starts</td>
<td>September 1, 2006</td>
<td></td>
<td></td>
<td>September 1, 2006</td>
</tr>
<tr>
<td>TBM Completion Date</td>
<td>August 15, 2008</td>
<td>April 28, 2011</td>
<td>March 30, 2011*</td>
<td></td>
</tr>
<tr>
<td>Substantial Completion Date</td>
<td>October 9, 2009</td>
<td>June 15, 2013</td>
<td>July 2, 2013</td>
<td>March 9, 2013</td>
</tr>
<tr>
<td>Final Completion**</td>
<td>December 8, 2009</td>
<td>August 12, 2013</td>
<td>March 2014</td>
<td>March 6, 2014</td>
</tr>
</tbody>
</table>

* TBM mining was essentially complete on March 22, 2011 when the TBM was stopped a short distance from the inlet in preparation for a ceremonial “breakthrough event” on May 13, 2011. For contractual purposes, the completion date was certified as March 30, 2011.
** Final completion is an OPG internal date, and was not part of the ADBA.

The ADBA contractual Substantial Completion date of June 15, 2013 was changed to July 2, 2013 in Amendment 1 to the ADBA (June 29, 2012). This change was in accordance with the agreed target cost and schedule adjustments pre-defined for the Major Risk Event “Crown Overbreak” listed in Appendix 5.3C “Major Risk Table” of the ADBA. ADBA Amendment 2 (October 16, 2013) further modified the contractual Substantial Completion date to October 4, 2013. These changes were to reflect the effects of “fall of ground” events on September 11, 2009 and July 2, 2011, which were deemed to have resulted in an aggregate delay of 94 days.

Strabag was able to achieve a three-month earlier Substantial Completion date than had been planned in the ADBA. This was through a change in the approach to removal of some of the tunnel lining equipment. Rather than waiting to remove grouting and arch concrete carrier equipment from the intake end, which would have required keeping the cofferdam intact, Strabag determined that it was feasible to disassemble, back up and remove this equipment through the outlet end. This allowed the intake service gates to be closed in the fall of 2012, thereby permitting water up of the inlet area in November 2012. This in turn permitted earlier removal of the cofferdam, so that tunnel operation could begin in the spring of 2013.

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48 This was a contractual date with Strabag. The Board-approved in service date, which included a schedule contingency, was June 2010.
49 The Board-approved in service date for the Superseding Business Case, including the new schedule contingency, was December 2013.
5.4 Capital Cost
The Project estimates and actual costs (all costs in $M) were as follows:

<table>
<thead>
<tr>
<th>Item</th>
<th>Original Release</th>
<th>Superceding Release BCS</th>
<th>Dec 2015 Final Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPG Project Management</td>
<td>4.4</td>
<td>6.0</td>
<td>4.7</td>
</tr>
<tr>
<td>Owner’s Representative</td>
<td>25.4</td>
<td>40.4</td>
<td>36.1</td>
</tr>
<tr>
<td>Other Consultants</td>
<td>4.0</td>
<td>5.9</td>
<td>6.5</td>
</tr>
<tr>
<td>Environmental/Compensation</td>
<td>12.0</td>
<td>9.6</td>
<td>8.7</td>
</tr>
<tr>
<td>Tunnel Contract (including incentives)*</td>
<td>723.6</td>
<td>1,181.7</td>
<td>1,107.7</td>
</tr>
<tr>
<td>Other Contracts/Costs</td>
<td>78.9</td>
<td>69.8</td>
<td>66.1</td>
</tr>
<tr>
<td>Interest</td>
<td>136.9</td>
<td>286.6</td>
<td>234.5</td>
</tr>
<tr>
<td>Total Project Capital</td>
<td>985.2</td>
<td>1,600.0</td>
<td>1,464.2</td>
</tr>
</tbody>
</table>

* Excludes Removal Costs of $1.6 M for the Dewatering Structure and $3.0M for the Acceleration Wall charged to OM&A

The final Project cost includes $60 million paid to Strabag for the interim and substantial completion fees and the schedule performance incentive. The final cost is 49% more than the originally approved (2005) estimate, but is 8.5% less than the total approved in the Superseding BCS. All contingency used prior to the Superseding BCS was included as cost in the ADBA Target Cost. Of the $164M contingency amount contemplated in the Superseding BCS, $49M had been spent at Project completion. The OPG, OR and other consultant costs of $47.3 million make up slightly more than 3% of the total Project cost. This is somewhat lower than the normally expected range of 5 – 10% for project management of large capital projects.

5.5 Changes
Project records indicated that the Contractor as well as OPG and the OR managed changes in accordance with the contract requirements and the Project change management procedure. A project management audit conducted by OPG Internal Audit in 2010 did not report any negative findings regarding Project scope and change control.

Five amendments to the original DBA were issued between March 2006 and September 2008. The first of these amendments dealt primarily with the constitution and operation of the DRB. The second amendment was to transfer responsibility to the Contractor for the consequences of their decision not to use a grout curtain to restrict groundwater inflows during excavation of the channel at the outlet end of the tunnel (PCN1, PCD2). Amendment three dealt with several PCN claims related to Differing Subsurface Conditions affecting the excavation and construction at the intake and accelerating wall area. These were settled in October 2007 at a total cost of approximately $7.5 million, vs. the original claimed amounts totaling nearly $20 million.
Amendment four included some further modifications to the DRB operation as well as addressing 13 PCDs that represented approximately $418,000 in net cost increases for work at the intake end. Amendment five added the definition and operational rules around “deemed amendments” to the contract, and also addressed seven PCDs with a total cost impact of $219,000.

In total, the Contractor submitted 25 PCNs prior to the ADBA many of which were settled through the DBA amendments described above. However, a number of these PCNs, particularly PCN17, were related to the Differing Subsurface Conditions encountered during tunnel boring, including the fall of ground in May 2007. The DSC issues were the primary causes of the cost claims and schedule delay that lead to the renegotiation of the contract. Twelve PCNs were dispositioned through the $40 million settlement (PCD33) associated with negotiation of the ADBA.

The ADBA was amended three times: in June of 2012; October of 2013; and February of 2014. The changes included in the first two ADBA amendments, as well as “deemed amendments”, were as follows:

<table>
<thead>
<tr>
<th>PCD</th>
<th>Change Type</th>
<th>Amendment</th>
<th>Subject</th>
<th>Target Cost Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>35</td>
<td>Owners Mandatory Requirements</td>
<td>1</td>
<td>Change to intake and outlet gate material (stainless steel components specified)</td>
<td>$133,986</td>
</tr>
<tr>
<td>36</td>
<td>Deemed</td>
<td>Removal of tunnel sump pump at low point</td>
<td>($92,843)</td>
<td></td>
</tr>
<tr>
<td>37</td>
<td>Scope</td>
<td>Purchase of spare TBM main bearing</td>
<td>$1,746,952</td>
<td></td>
</tr>
<tr>
<td>38</td>
<td>Deemed</td>
<td>Decommissioning of boreholes</td>
<td>$92,843</td>
<td></td>
</tr>
<tr>
<td>39</td>
<td>Deemed</td>
<td>Disputed difference in pre-effective date loss (Outcome of dispute resolution)</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>40</td>
<td>Deemed</td>
<td>Temporary ventilation shaft near Stanley Ave.</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>41</td>
<td>Deemed</td>
<td>Change of full surface leak detectable waterproofing system for the tunnel arch</td>
<td>$0 (expected cost saving of $3.5 million)</td>
<td></td>
</tr>
<tr>
<td>42</td>
<td>Scope</td>
<td>Supply, installation and monitoring of profile monitoring instrumentation at the Rankine Generation Station (to monitor horizontal rock movement during tunnel excavation)</td>
<td>$185,000</td>
<td></td>
</tr>
<tr>
<td>43</td>
<td>Security Document</td>
<td>2</td>
<td>ILF Specified Professions Professional Liability Insurance</td>
<td>$0</td>
</tr>
<tr>
<td>44</td>
<td>Deemed</td>
<td>Additional site areas made available to the Contractor</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>45</td>
<td>Scope</td>
<td>Drilling and sampling in the tunnel for potential swelling at low point study by K.Y. Lo</td>
<td>$185,000</td>
<td></td>
</tr>
<tr>
<td>46</td>
<td>Change in Law</td>
<td>1</td>
<td>Harmonized Sales Tax (provision to adjust cost after elimination of ORST)</td>
<td>($2,485,671) (2010,2011)</td>
</tr>
<tr>
<td>47</td>
<td>Scope</td>
<td>Engage Robbins in design of TBM main beam repair (December 2010 event)</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>48</td>
<td>Risk Events</td>
<td>1</td>
<td>Crown overbreak adjustment (per ADBA)</td>
<td>$10,454,848</td>
</tr>
<tr>
<td>49</td>
<td>Scope</td>
<td>Return of spare TBM main bearing</td>
<td>($1,527,120)</td>
<td></td>
</tr>
<tr>
<td>50</td>
<td>Owners</td>
<td>Appears not to have proceeded beyond a draft</td>
<td></td>
<td></td>
</tr>
<tr>
<td>51</td>
<td>Owners</td>
<td>Outlet gates: Welding receptacles, utility outlets, and</td>
<td>$19,115</td>
<td></td>
</tr>
</tbody>
</table>
Target Cost adjustments totaled $9,003,567 for Amendment 1 and $23,450,528 for Amendment 2.

Amendment 1 to the ADBA also changed the Target Substantial Completion Date from June 15, 2013 to July 2, 2013 as part of the adjustment for the crown overbreak risk event (PCD048). Amendment 2 again adjusted the Target Substantial Completion Date from July 2, 2013 to October 4, 2013 based on the total 94-day delay attributed to the fall of ground events in September 2009 and July 2011. However, the actual Substantial Completion Date was achieved on March 9, 2013, considerably before the adjusted target date.

The original ADBA required the Contractor to provide a Letter of Credit, to cover the cost of any tunnel performance shortfalls or Contractor defaults, which was to be in effect until the Final Completion date (effectively the date on which all work was to be done.) The ADBA also required the Contractor to submit a Maintenance Bond to guarantee the cost of any required warranty work over the period of one year after
Substantial Completion (the date on which the facility was ready to use.) Amendment 3 eliminated the requirement for the Maintenance Bond but extended the duration of the Letter of Credit to cover any outstanding obligations.

The contract with HMM was amended in August 2010 to increase the value from $23.32 million to $47 million, to provide OR services for the remaining, extended duration of the Project. Actual final OR costs were well within the amended limit.

5.6 Quality

5.6.1 Performance

Tunnel flow testing was performed to verify that the contractual Guaranteed Flow Amount (GFA) of 500 m$^3$/s had been achieved. Alden Research Laboratory, a US firm, carried out the tests under subcontract to Strabag in July 2013.

The test apparatus included temporary water level gauges installed in the intake channel and outlet canal, and ultrasonic flow measuring transducers at the outlet of the tunnel, just upstream of the outlet gate structure. The multipath ultrasonic flowmeter measured flow by sending pulses between pairs of transducers located on opposite walls of the tunnel. Data was captured and recorded in real time through a wireless internet-enabled system. After a one-hour period to stabilize flow through the tunnel, water level and flow rate data was recorded for a 100-minute period early in the morning of July 24, 2013.

The test results were as follows:

<table>
<thead>
<tr>
<th>Table 5.7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Upstream Water Level</td>
</tr>
<tr>
<td>Average Downstream Water Level</td>
</tr>
<tr>
<td>Average Flow Meter Reading</td>
</tr>
<tr>
<td>Performance Test Flow Water Amount (PTFWA)</td>
</tr>
</tbody>
</table>

The “Performance Test Flow Water Amount” (PTFWA) as defined in the ADBA$^{50}$ was the flowrate calculated by Alden for contractual guarantee purposes by adjusting for changes in the reference hydraulic head, in this case 5.6 m, due to the geometry of the outlet canal. The formula for this calculation was given in the ADBA.

The ADBA allowed for a difference of +/- 2% of the PTFWA (i.e. 9.9 m$^3$/s) from the GFA before any performance incentives or disincentives would apply. Since the PTFWA was within this 2% tolerance, the flow performance objective was met and no liquidated damages or bonuses applied to the contract.

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$^{50}$ No change was made between the original DBA and the ADBA regarding the guaranteed flow.
5.6.2 Construction Quality

Initially there were some issues with the implementation of the Strabag and subcontractor quality programs, leading to replacement of some Contractor quality management staff. Generally, however, OPG Project staff expressed satisfaction with the overall final quality of the Contractor’s work.

Early in the Project while the OR performed the quality oversight function, OPG was advised of nonconformances but was generally copied on formal nonconformance notices (NCNs) only after they had been closed out following disposition by the Contractor and OR. Disposition actions could include repair, replace, or use “as is”.

An OPG internal audit conducted in June 2010 noted that although the OR was closely monitoring the quality of the Contractor’s work there was “no structured reporting from the OR to the project team or in the Monthly Report to record recurring problems, the extent of condition, and corrective actions of permanent works.” In response, OPG and the OR increased the detail of quality reporting and introduced quality trending to better track recurring problems.

Over the course of the Project, 68 Nonconformance Notices were issued. These can be generally categorized as follows:

<p>| Table 5.8 |</p>
<table>
<thead>
<tr>
<th>Work Area/Activity</th>
<th>No. of NCNs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concrete quality and placement</td>
<td>26</td>
</tr>
<tr>
<td>Intake area – accelerating and approach walls</td>
<td>13</td>
</tr>
<tr>
<td>Dewatering System - shaft location, installation</td>
<td>9</td>
</tr>
<tr>
<td>Waterproofing – membrane problems</td>
<td>4</td>
</tr>
<tr>
<td>Outlet area</td>
<td>4</td>
</tr>
<tr>
<td>Shotcrete</td>
<td>3</td>
</tr>
<tr>
<td>Grouting</td>
<td>3</td>
</tr>
<tr>
<td>Other (tunnel alignment, support rings, blasting, etc.)</td>
<td>6</td>
</tr>
</tbody>
</table>

For 24 of the NCNs the disposition action was to use “as is”. For the remainder, remedial action such as repair or replace was required and completed.

One significant problem, that could potentially have affected the 90 year service life of the tunnel – a key Project objective - was identified in 2009 and is briefly described below as an indication of the investigation and problem solving approach used for resolving quality issues.

In October 2009, when TBM mining was approximately 50% complete, a routine tunnel inspection indicated that water had migrated down the tunnel and leaked into a void between the invert concrete and the tunnel wall, in the vicinity of the tunnel low point about 1400 m from the outlet end. The trapped water was observed exiting from the water release holes and also from radial construction joints. The water from the release
holes was saline which indicated that fresh water from the upper formations was traveling through the salty Queenston formation, most likely along the shotcrete boundary or deeper within the fracture zone around the tunnel excavation. Moisture could also be seen on the tunnel shotcrete walls (final arch concrete installation had not yet started) at various locations along the tunnel within the Queenston formation despite this formation being highly impermeable and dry. This indicated that water was present on both sides of the waterproofing membrane. The issue was formally communicated to Strabag by OPG in November 2009 through “Notice of Defective Tunnel Facility Project No. 001.”

The water was removed from the affected section of the tunnel and a system of drains, sumps and pumps was installed to prevent further infiltration of water into the Queenston Shale under the invert. The invert was repaired by removing the cracked areas by intersecting core holes and installing non-shrink concrete with a strength at least equal to that of the liner concrete. Repair costs for this work were Disallowed Costs under the ADBA.

This event raised several concerns that fresh water leakage could potentially have compromised the integrity of the invert liner membrane and resulted in stresses on the tunnel from swelling of the surrounding rock due to the water penetration. It appeared that:

- The concrete invert liner had “floated”, potentially allowing debris to enter between the concrete and the membrane; and
- The combination of movement of the concrete invert, trapped debris and loading from construction traffic could have damaged the membrane and comprised its ability to prevent water from leaking through the operating tunnel into the surrounding Queenston Shale.

After analyzing the alternatives and risks a decision was made to continue with tunnel construction, including installation of the membrane and arch concrete liner, while testing and analysis was done to assess the long-term impacts of the event. This work was done between 2010 and 2012.

K. Y. Lo Inc. was contracted to supervise the drilling and extraction of representative core samples of the Queenston Shale from the invert and side walls of the tunnel at the low point and to do testing to establish the swelling potential due to the water that had already infiltrated behind the membrane and the potential swelling that would occur if fresh water infiltration continued through holes in a damaged membrane. The testing confirmed that:

- Fresh water had infiltrated into the Queenston Shale;
- Chloride ion diffusion had occurred, reducing the salinity of the rock under the invert;
The swelling process had started; and

The effected swelling zone extended from the low point CH1+416 to CH1+720 and down approximately 1.2 m below the invert; a transition zone of partially affected rock extended from 1.2 to 1.8 m below the invert

ILF (Strabag’s engineering subcontractor) then did a finite element analysis of the potential swelling loading from the Queenston Shale and concrete liner interaction under a number of load cases to establish the worst case conditions for continued swelling and the capacity of the concrete liner to resist the swelling loads over the design life of the tunnel. The OR later did its own analysis to verify the ILF findings.

MFPA Leipzig was contracted to carry out tests to determine if the membrane could have been damaged by the flooding, floatation of the concrete invert, and construction loading. This was followed by a series of tests to determine if the contact and interface grouting process could effectively seal the damaged membrane and restore the watertight barrier. This work was supervised by ILF and witnessed by the OR.

The two independent finite element analyses of the rock and lining interface showed that the as-built concrete liner had sufficient structural capacity, compliant with code requirements, to resist all the applied loads including the swelling loads derived from the K.Y. Lo swelling potential analysis. Tests on simulations of the as-constructed lining system showed that the contact and interface grouting would effectively seal the damaged membrane and prevent water penetration into the rock and therefore prevent chloride ion diffusion from the rock for all loading conditions for the design life of the tunnel.

Following the investigations and analysis it was concluded that the as-built tunnel liner, with the concrete invert repairs, complied with the Owner’s Mandatory Requirements and applicable code requirements. Therefore, although it cannot be conclusively demonstrated at this time, it would appear that the 90-year service life for the Tunnel will be achievable.

5.7 Community Impacts
One of the key requirements of the Niagara Plant Group, as the ultimate user of the completed facility was to maintain a good working relationship with stakeholders, contractors and the affected public. The following table shows the outcomes observed versus the measures established as part of the related Project objective:

<table>
<thead>
<tr>
<th>Measure</th>
<th>Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zero Treaty violations concerning Falls flow</td>
<td>No violations</td>
</tr>
<tr>
<td>Zero International Niagara Board of Control (INBC) Directive violations concerning Grass Island Pool (GIP) operation</td>
<td>No violations</td>
</tr>
<tr>
<td>Zero ice management incidents</td>
<td>No incidents</td>
</tr>
</tbody>
</table>
6 Risk Events

The following table shows actual outcomes against the major Project risks identified in the original (2005) business case.

<table>
<thead>
<tr>
<th>Risk</th>
<th>Potential Consequences</th>
<th>Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Report (GBR)</td>
<td>Unexpected, adverse subsurface conditions could slow tunnel construction and require the Contractor to undertake remedial / extra work resulting in legitimate claims for extra costs and / or schedule extension for differing subsurface conditions (DSC).</td>
<td>Mining the Queenston Shale proved to be more difficult than anticipated due to the high horizontal stresses in the rock. Following resolution of a DSC claim, the Design-Build Agreement had to be amended to provide the Contractor with cost and schedule relief. The consequence was an increase of $479 million (49%) in the final Project cost vs. the release estimate, and a delay of 41 months beyond the original contractually agreed 50-month schedule to Substantial Completion.</td>
</tr>
<tr>
<td>OPG resources with knowledge and experience required for design and construction of a major tunnel are severely limited.</td>
<td>OPG resource limitations could have significant impacts on Project quality, cost and schedule.</td>
<td>Use of Hatch Mott MacDonald as the Owner’s Representative, who provided most of the project and construction management resources, effectively mitigated this risk to the extent possible.</td>
</tr>
<tr>
<td>Queenston Shale, the host rock formation for the majority of the tunnel, has swelling properties when exposed to fresh water.</td>
<td>Swelling of the Queenston Shale surrounding the tunnel could over-stress the tunnel lining and cause damage that would interrupt flow through the tunnel and require expensive remedial work.</td>
<td>The tunnel incorporates an impermeable membrane and prestressed concrete/grout liner that have been designed and tested to prevent leakage of water from the tunnel into the surrounding rock. One leakage event occurred during construction, resulting in potential swelling of the Queenston Shale at the tunnel low point. Extensive testing and analysis following the event concluded that the liner design meets all design requirements, even with a potentially damaged membrane.</td>
</tr>
</tbody>
</table>
The following table shows the outcomes against the OPG Key Risks\textsuperscript{51} that were monitored during the ADBA period:

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|}
\hline
\textbf{Risk} & \textbf{Potential Consequences} & \textbf{Outcome} \\
\hline
1 & Major TBM breakdown including main bearing failure & Construction delay & Spare TBM main bearing was procured but was not needed and was returned for credit. A crack in the TBM main beam in December 2010 resulted in a shutdown of three weeks. However, overall mining completion date was not delayed. \\
\hline
2 & Main conveyor failure & Construction delay & Risk did not occur \\
\hline
3 & Inundation of tunnel after TBM breakthrough due to breach of cofferdam & Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities & Risk did not occur \\
\hline
4 & Critical marine work (cofferdam removal) impeded by marine operational constraints (ice conditions) at INCW & Construction delay & Risk did not occur. Change in Contractor’s plan allowed for early removal of cofferdam before ice became a problem. \\
\hline
5 & Tunnel collapse due to inadequate design or construction or ground conditions & Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities & Risk did not occur \\
\hline
\end{tabular}
\end{table}

\textsuperscript{51} This list represents risks under active management as of late 2012. As noted in Section 4.6.3 the Key Risks were, in general, a higher-level summarization of the earlier detailed risk register.
<table>
<thead>
<tr>
<th>Risk</th>
<th>Potential Consequences</th>
<th>Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>Delay in removal of outlet plug due to OPG inability to provide a PGS outage when required</td>
<td>Construction delay</td>
</tr>
<tr>
<td>7</td>
<td>Profile restoration delayed due to prototype operation for restoration equipment and delays in procurement and delivery of equipment</td>
<td>Construction delay</td>
</tr>
<tr>
<td>8</td>
<td>Overall progress delayed due to the logistics of concurrent construction operations (TBM mining, invert concrete, profile restoration, arch concrete, grouting)</td>
<td>Construction delay</td>
</tr>
<tr>
<td>9</td>
<td>Permanent works defective or do not conform with specifications due to construction quality (includes permanent works concrete deficiencies)</td>
<td>Cost increase and construction delay</td>
</tr>
<tr>
<td>10</td>
<td>Project costs increase due to contract management problems including claims and oversight of Contractor</td>
<td>Cost increase</td>
</tr>
<tr>
<td>11</td>
<td>Contractor defaults on its obligations due to potential for significant loss</td>
<td>Cost increase and construction delay</td>
</tr>
<tr>
<td>12</td>
<td>Ground convergence exceeding specifications delays installation of the final concrete lining</td>
<td>Construction delay</td>
</tr>
<tr>
<td>13</td>
<td>Fire in tunnel due to hot works, faulty equipment, flammable gases and liquids, open flames, smoking</td>
<td>Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities</td>
</tr>
<tr>
<td>14</td>
<td>Major environmental/regulatory infraction due to reportable spill or discharge that results in a charge under federal or provincial legislation or regulations or under a municipal bylaw</td>
<td>Regulatory orders and charges, third party actions, reputational damage</td>
</tr>
<tr>
<td>15</td>
<td>Major safety incident due to construction related accident or work stoppage</td>
<td>Regulatory orders and charges, personnel injuries or fatalities, reputational damage</td>
</tr>
<tr>
<td>Risk</td>
<td>Potential Consequences</td>
<td>Outcome</td>
</tr>
<tr>
<td>------</td>
<td>------------------------</td>
<td>---------</td>
</tr>
<tr>
<td>16</td>
<td>Fall of ground due to inadequate design and/or construction of ground support and inadequate monitoring of convergence and support condition</td>
<td>Damage to tunnel, damage to or loss of equipment, delay in construction, personal injuries or fatalities</td>
</tr>
<tr>
<td>17</td>
<td>Arch concrete progress delayed due to initial setup delays and equipment failures during ongoing operation</td>
<td>Cost increase and construction delay</td>
</tr>
<tr>
<td>18</td>
<td>Pre-stress grouting progress delayed due to initial setup delays and equipment failures during ongoing operation</td>
<td>Cost increase and construction delay</td>
</tr>
<tr>
<td>19</td>
<td>Swelling of ground in the tunnel invert at the low point due to exposure to water</td>
<td>Cost increase due to rework</td>
</tr>
<tr>
<td>20</td>
<td>Loss of key Project personnel due to length of Project</td>
<td>Cost increase and construction delay</td>
</tr>
<tr>
<td>21</td>
<td>Progress of final lining delayed by concrete delivery problems due to lack of a reliable off-site concrete supply that meets specifications</td>
<td>Cost increase and construction delay</td>
</tr>
</tbody>
</table>

The original Business Case identified a number of business-related risks as repeated in the table below along with the current outcomes:

**Table 6.3**

<table>
<thead>
<tr>
<th>Risk</th>
<th>Potential Consequence</th>
<th>Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inability of OPG to fully recover the Project costs through the Regulated Rate</td>
<td>Adverse financial impact on OPG</td>
<td>The OEB approved recovery of $1,387M of the $1,464M total costs.</td>
</tr>
<tr>
<td>OPG has retained the hydrologic risk (uncertainty regarding Niagara River flow).</td>
<td>Incremental average annual energy output from the SAB complex could be less than 1.6 TWh resulting in a need to increase base load hydroelectric energy rates to recover Project</td>
<td>Energy output is now forecast to be 1.5 TWh</td>
</tr>
<tr>
<td>Successful claim by others in Canada or the United States to use Niagara River water available for power generation that exceeds OPG’s capacity.</td>
<td>OPG could lose rights to use some of the Niagara River water available for power generation.</td>
<td>The NEA grants exclusive water rights to OPG. Successful completion of the tunnel ensures continuing rights to the water.</td>
</tr>
</tbody>
</table>

7  Project Closeout
As of the date of this PIR, the Project has been placed 100% in service, but has not yet been formally closed out. Some final documentation is still outstanding. Also, the flowmeters installed in the tunnel have apparently failed, although the reason for this is not known.

8  Lessons Learned
A facilitated Project lessons learned meeting was held in April 2007 with OPG and HMM Project staff to discuss and document experiences with the first phase of the INCW Part Project. Much of the discussion centred on the safety management aspects of the work, for which OPG was the Constructor. Some of the key observations from this meeting were that:

- Job Safety Analyses were a new tool for some of the subcontractors but by having OR-prepared JSAs provided as examples, the subcontractors were able to more easily adopt the methodology;
- Work protection training for the subcontractor workers should have been more site-specific;
- Having OPG Niagara River Control Centre staff coordinate the work protection process, and having the OR hold work protection, had been effective;
- During visits MOL inspectors would apply codes and standards other than those from the Construction Regulations⁵² when issuing orders, and in some cases would write orders without fully verifying the requirements; and

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⁵² This practice was not unique to MOL inspections of the Niagara Tunnel Project. It has been applied on other OPG work sites in the past.
• The handoff from the Part Project from Constructor back to Owner Only status required some improvement to facilitate a smoother transfer.

A second formal facilitated lessons learned meeting was held in July 2013 after the tunnel had been placed in-service. The full list of lessons gathered in that meeting is shown in Appendix D.

Some additional observations and recommendations regarding lessons from the Niagara Tunnel Project follow:

### 8.1 Contracting Method

At the outset of the Project there was a strong desire on the part of the OPG Board and senior management to a) transfer as much of the risk in the Project as possible to the Contractor, and b) obtain as much up-front price and schedule certainty as possible. This was understandable at the time, given the lack of recent OPG experience with tunneling projects and the need to re-establish confidence in OPG’s ability to manage a major project without significant cost or schedule overruns. The original strategy for allocation of the DSC risk and to provide a basis for a fixed price contract was to establish with the Contractor the agreed Geotechnical Baseline Report C that would define the expected subsurface conditions and to rely on an independent Dispute Review Board to adjudicate any claims arising from differing conditions. The probability and cost/schedule impact of encountering much more adverse conditions were, in hindsight, underestimated by both the Contractor and the OPG/OR Project team to the extent that the original Project contingencies for these events were inadequate. In the end, the risk-sharing mechanism later adopted for the ADBA was a more cost-effective way of dealing with this type of risk than the original approach. Some key features of the ADBA that contributed to its success were:

• Establishment of a detailed cost estimating model agreed on by both parties for the remaining portion of the tunneling work, which could form the basis of the contract Target Cost. One important element of this model was the use of different productivity rates\(^{53}\) for different rock conditions. Another element was the use of baseline costs for certain items such as escalation and the cost of diesel fuel where there was some uncertainty or disagreement about future costs. Adjustments for actual costs could then be made with reference to the agreed baseline. As work under the ADBA continued the detailed estimating model also provided a tool for calculating accurate projections of the forecast cost to completion;

• Pre-defining what would be considered Allowed or Disallowed costs. In particular, the costs of rework due to Contractor quality issues that were found

\(^{53}\) It might be argued, of course, that even under the original DBA these productivity rates could not have been known in advance of the actual work. However, an up-front agreement on expected rates, with an adjustment mechanism, could still have formed the basis of a target cost.
by the OR were defined in the ADBA as Disallowed costs. This provided a strong incentive for an effective Contractor quality control system;

- Establishing an equitable method for sharing the risks and benefits of deviations from the Target Cost and Target Schedule. This included sufficient incentives to encourage innovation and productivity as well as disincentive limits that would avoid unacceptable losses to the Contractor, thus ensuring that the Contractor would not default and the work would be completed;

- Pre-defining important risk events, such as excessive overbreak, that could occur with an associated unit cost mechanism for a fair adjustment of the Target Cost and Schedule for the work;

- A requirement for OPG pre-approval of Contractor materials and services with a cost of more than $100,000. This was intended to help ensure that the Contractor was applying value for money principles when making major purchases for the work; and

- Use of “open book”, audited cost monitoring with the Contractor. This allowed OPG to verify that all claimed costs were in fact legitimate.

It should be noted that those portions of the work that were considered well-defined and relatively low risk, such as the intake and outlet structure civil works subcontracts, remained fixed-price components of the overall contract and were not subject to all of the additional provisions listed above.

Although not perfect, the ADBA should prove to be a valuable template for OPG to adapt and use for future contracts of this type.

8.2 Risk Management Strategies
To avoid the temptation to assume that Design-Build or fixed price contracting with liquidated damages are automatically the best risk-limiting strategies for future projects, OPG should ensure that a wider range of contracting options and strategies is systematically examined, before deciding on a final approach. This would allow the benefits and risks of each option to be compared in the context of the overall objectives and priorities of the project. One effective method for doing this would be to use the Project Delivery and Contracting Strategy (PDCS)\(^{54}\) tool developed by the Construction Industry Institute. This tool provides a means of comparing the effectiveness of different strategies in meeting a prioritized list of Owner-defined project objectives.

The practice of sharing non-commercial risk information with the DB Contractor, required by the insurance underwriters, was effective in promoting more open communication between the parties with respect to both risk identification and risk mitigation. This approach also ensured that the responsibility for risk management was clearly assigned and accepted. Involving major contractors directly and as early as

\(^{54}\) CII Publication RS165-1 – Owner’s Tool for Project Delivery and Contract Strategy Selection
possible in risk management activities is a practice that should be considered for all projects.

The use of Excel® as the tool for risk management for the NTP had several drawbacks, including:

- Multiple versions of the risk registers had to be created for different analysis, tracking and reporting purposes;
- It was difficult to track the history of risk management activities, e.g. when risks were identified, if/when they actually occurred, when they were closed and, when mitigating actions were completed, etc.; and
- Risk registers did not provide a means to differentiate between risk owners and those responsible for risk mitigation activities (they may not have been the same individuals).

For future major projects it would be highly desirable to procure and use a project risk management database tool as the single repository for all project risk information. Customized risk reports could then be generated for different purposes and audiences.

8.3 Safety and Environmental Management

Through the Owner Only structure for the NTP, OPG was able to effectively contain its exposure to risks associated with construction health and safety and some environmental aspects of the Project. However, the Contractor’s management of risks to worker safety and the environment was, at best, only satisfactory. In addition to requirements to conform to applicable recognized international standards a number of contract terms and conditions might be considered to improve conformance to OPG’s expectations on future major projects, even under an Owner Only arrangement:

- Mandate (and be prepared to pay for) a specified minimum number of full time on-site staff to oversee health and safety and environmental management;
- Require the contractor to demonstrate through records of experience and qualifications that health and safety and environmental management staff have the requisite competence to meet minimum requirements defined by OPG;
- Mandate a contractor project team reporting relationship that prevents giving a higher priority to production than to health and safety and environmental management. Ideally, to maintain the required level of influence, contractor health and safety and environmental management staff should not report directly to, but have only a “dotted line” reporting relationship to, the contractor project manager;
- Provide a contractual mechanism for periodic meetings between OPG and contractor senior management (above project level) to discuss contractor performance and continually reinforce OPG’s expectations; and

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55 This type of tool would have to be chosen specifically for project management purposes and would not be the same as an enterprise risk management system.
• Require at least annual independent, third party audits of the contractor’s health and safety and environmental management systems as applied to the specific project, with payment-related timelines for rectification of non compliances and verification of corrective actions (i.e. portions of progress payments to be withheld until compliance can be satisfactorily demonstrated).

9 Conclusions
The Niagara Tunnel Project was ultimately successful in providing a facility capable of delivering the required additional flow of 500 m³/s to the SAB complex. The final Project cost was 8.5% less than the revised target approved in the Superseding Business Case, and the Project achieved Substantial Completion 14 weeks ahead of the revised contract Target Schedule date. Therefore, only 19% of the approved cost contingency, and none of the schedule contingency, was required.

Risk management for the Project was carried out in conformance with established governance as well as generally accepted best practices for both qualitative and quantitative assessments. Risk mitigating actions were defined and completed as planned for anticipated events. An independent expert concluded that the geotechnical investigations undertaken prior to the Project were “professionally complete and met or exceeded in some cases the professional standards for work of similar type and magnitude”\(^{56}\). Therefore the schedule delay and additional costs of the Project – with respect to the original 2005 Business Case approval - were due almost entirely to the unexpectedly difficult and unforeseen subsurface conditions within the Queenston Shale formation. It was these conditions that resulted in extensive crown overbreak, leading to lower TBM mining rates and the need to re-profile the tunnel prior to installation of the final liner.

OPG and the OR have expressed satisfaction with the final design and construction quality of the facility provided by the Contractor. The Contractor’s safety and environmental management performance was acceptable.

An important objective of the Project was to maintain the good community and stakeholder relationships that the Niagara Plant Group had established over the years. Despite the scale and duration of the Project, this objective was successfully met.

A review of the project management system applied on the Project, which has been only briefly summarized in this report, demonstrated that its planning and execution was consistent with the Project Management Body of Knowledge (PMBOK) published by the Project Management Institute. In addition OPG and the OR employed a number of general recognized project management “best practices” (e.g. pre-project planning, PDRI, team building, dispute resolution, etc.). Overall, the Project was managed in a

very competent and professional manner, with a high level of teamwork and cooperation maintained between all participants despite the challenges encountered. A good working relationship between the parties from the outset of the Project facilitated negotiation of a mutually acceptable Amended Design-Build Agreement avoiding a lengthy and expensive contract dispute.
Abbreviations and Acronyms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADBA</td>
<td>Amended Design-Build Agreement</td>
</tr>
<tr>
<td>BCS</td>
<td>Business Case Summary</td>
</tr>
<tr>
<td>CIA</td>
<td>Community Impact Agreement</td>
</tr>
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<td>CPI</td>
<td>Cost Performance Index</td>
</tr>
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<td>DB</td>
<td>Design-Build</td>
</tr>
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<td>DBA</td>
<td>Design-Build Agreement</td>
</tr>
<tr>
<td>DRB</td>
<td>Dispute Review Board</td>
</tr>
<tr>
<td>DSC</td>
<td>Differing Subsurface Conditions</td>
</tr>
<tr>
<td>EA</td>
<td>Environmental Assessment</td>
</tr>
<tr>
<td>FOG</td>
<td>Fall of Ground</td>
</tr>
<tr>
<td>JSA</td>
<td>Job Safety Analysis</td>
</tr>
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<td>MNR</td>
<td>Ministry of Natural Resources</td>
</tr>
<tr>
<td>MOE</td>
<td>Ministry of the Environment</td>
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<tr>
<td>MOL</td>
<td>Ministry of Labour</td>
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<td>NCR</td>
<td>Non Conformance Report</td>
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<td>NRHD</td>
<td>Niagara River Hydroelectric Develop</td>
</tr>
<tr>
<td>OPA</td>
<td>Ontario Power Authority</td>
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<tr>
<td>OR</td>
<td>Owner’s Representative</td>
</tr>
<tr>
<td>PCD</td>
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<td>PCN</td>
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<td>PDRI</td>
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<td>PEP</td>
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<td>PRM</td>
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<td>RFI</td>
<td>Request for Information</td>
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<tr>
<td>RFP</td>
<td>Request for Proposal</td>
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<tr>
<td>SPI</td>
<td>Schedule Performance Index</td>
</tr>
<tr>
<td>TBM</td>
<td>Tunnel Boring Machine</td>
</tr>
</tbody>
</table>
References

Note: While in some cases the originating organization is shown, specific author names/affiliations are not
provided because in most cases there were either multiple authors, or, author names were not shown on
the documents. Similarly, many documents reviewed did not have a Document Number assigned.

<table>
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<th>Document Title</th>
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<tr>
<td>Health &amp; Safety Incident Summary</td>
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<td>2-Dec-13</td>
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<tr>
<td>Niagara Tunnel Facility Project Nonconformance Register</td>
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<td>11-Sep-13</td>
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<tr>
<td>Niagara Tunnel Project - Quality Management Diligence Review (Memo from OPG to OR)</td>
<td>NAW130-01900 T5</td>
<td>1-Mar-12</td>
</tr>
<tr>
<td>Document Title</td>
<td>Document Number</td>
<td>Date</td>
</tr>
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<td>-------------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>Environmental Compliance Observations and Contractor Response</td>
<td>NAW130-07000.24-T5</td>
<td>30-Nov-11</td>
</tr>
<tr>
<td>Notice of Defective Tunnel Facility Project 001</td>
<td>NAW130-00061.09 ID047 R-NAW130-29230-0114</td>
<td>12-Nov-09</td>
</tr>
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<td>Niagara Tunnel Project Low Point - Water Infiltration and Potential Swelling of Queenston Shale (HMM Report)</td>
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<td>1-Feb-13</td>
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<td>Niagara Tunnel Facility Project Flow Verification Tests Final Results (Strabag/Alden)</td>
<td>R-NAW130-62900-0003 Rev 02</td>
<td>20-Sep-13</td>
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<tr>
<td>Audit of Safety Management - Niagara Tunnel INCW Part Project (Memo)</td>
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<td>7-Sep-06</td>
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<td>2007 Niagara Tunnel Facility Project Environmental Management Audit (Memo)</td>
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<td>16-Nov-07</td>
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<td>Internal Audit Niagara Tunnel Facility Project - Amended Design/Build Agreement</td>
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<td>1-May-10</td>
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<tr>
<td>Internal Audit Niagara Tunnel Project, Execution Phase</td>
<td></td>
<td>1-Jun-10</td>
</tr>
<tr>
<td>Internal Audit Strabag Contract Audit</td>
<td></td>
<td>1-Oct-11</td>
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<tr>
<td>Internal Audit Niagara Tunnel Project (NTP)</td>
<td></td>
<td>1-Oct-12</td>
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</tbody>
</table>
### Appendix A – Project Chronology

#### Feasibility/Concept/Definition Phases

<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone / Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>1982-1987</td>
<td>Comprehensive Conceptual Analysis</td>
</tr>
<tr>
<td></td>
<td>• Potential development alternatives analyzed</td>
</tr>
<tr>
<td></td>
<td>• Geotechnical investigations conducted</td>
</tr>
<tr>
<td></td>
<td>• Recommended the development of additional diversion and generation capacity at</td>
</tr>
<tr>
<td></td>
<td>the Sir Adam Beck complex</td>
</tr>
<tr>
<td>08-Aug-1988</td>
<td>Ontario Hydro Board Authorizes Project Definition Activities</td>
</tr>
<tr>
<td></td>
<td>• Included preliminary engineering and an environmental assessment</td>
</tr>
<tr>
<td>Mar-1991</td>
<td>Ontario Hydro Submits Environmental Assessment (“EA”) for Niagara River Hydroelectric Development (“NRHD”)</td>
</tr>
<tr>
<td></td>
<td>• Proposed NRHD included two new tunnels, a three-unit 1050 MW underground</td>
</tr>
<tr>
<td></td>
<td>generating station (referred to as Beck 3), and transmission improvements in the</td>
</tr>
<tr>
<td></td>
<td>Niagara Peninsula</td>
</tr>
<tr>
<td></td>
<td>• Allowed for staging of the project (i.e. the diversion facilities, one or both</td>
</tr>
<tr>
<td></td>
<td>tunnels, could proceed in advance of the generation and transmission facilities)</td>
</tr>
<tr>
<td>22-Dec-1993</td>
<td>Community Impact Agreement (“CIA”) Signed</td>
</tr>
<tr>
<td></td>
<td>• CIA signed between Regional Municipality of Niagara, Town of Niagara-on-the-Lake,</td>
</tr>
<tr>
<td></td>
<td>City of Niagara Falls and Ontario Hydro for tourism, road upgrades and facility</td>
</tr>
<tr>
<td></td>
<td>improvements that would be necessary if the NRHD were to proceed</td>
</tr>
<tr>
<td></td>
<td>• CIA was based on the full NRHD with estimated construction duration of 7 years</td>
</tr>
<tr>
<td></td>
<td>and estimated peak construction workforce of 800</td>
</tr>
<tr>
<td>Feb-1998</td>
<td>Ontario Hydro Initiates Review of Phase 1 of NRHD</td>
</tr>
<tr>
<td></td>
<td>• Decision to initiate Phase 1 (construction of one new tunnel)</td>
</tr>
<tr>
<td>Apr-1998</td>
<td>Ontario Hydro Retains the Beck Diversion Group (“BDG”) as the Owner’s Representative for Project</td>
</tr>
<tr>
<td></td>
<td>• Acres International Limited, Bechtel Canada and Hatch Mott MacDonald comprised</td>
</tr>
<tr>
<td></td>
<td>BDG</td>
</tr>
<tr>
<td>Jun-1998</td>
<td>Ontario Hydro Solicits Bids for Phase 1 of NRHD</td>
</tr>
<tr>
<td></td>
<td>• Solicited bids for detailed design and construction of one new tunnel</td>
</tr>
<tr>
<td></td>
<td>• Bids received in Sept-1998 and analyzed in Oct-1998 resulting in a recommendation for award</td>
</tr>
<tr>
<td>14-Oct-1998</td>
<td>Complete NRHD receives EA Approval</td>
</tr>
<tr>
<td></td>
<td>• EA approval provided Ontario Hydro with the flexibility to undertake the</td>
</tr>
<tr>
<td></td>
<td>development in phases</td>
</tr>
<tr>
<td>Dec-1998</td>
<td>Ontario Hydro Delays Award of Contract</td>
</tr>
<tr>
<td></td>
<td>• Ontario Hydro informs bidders that given the imminent reorganization of the</td>
</tr>
<tr>
<td></td>
<td>Corporation, the final decision regarding the tunnel would be deferred until</td>
</tr>
<tr>
<td></td>
<td>after April 1999</td>
</tr>
</tbody>
</table>

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57 From OEB submission EB-2013-0321 Exhibit D1 Tab 2 Schedule 1
<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone / Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jun-1999</td>
<td>OPG Decides to “Defer Indefinitely” the Project</td>
</tr>
<tr>
<td></td>
<td>• OPG decided to focus on other major projects (e.g., return to service of Pickering A) before committing to construct the new tunnel</td>
</tr>
<tr>
<td>Nov-2002</td>
<td>Province States It Will Direct OPG to Proceed with New Water Diversion Tunnel</td>
</tr>
<tr>
<td></td>
<td>• The Province subsequently indicated a strong desire to have the project completed in the shortest possible timeframe</td>
</tr>
<tr>
<td>24-Jun-2004</td>
<td>OPG Board of Directors Approves Preliminary Release</td>
</tr>
<tr>
<td></td>
<td>• Preliminary release of $10M to conduct a Request for Proposal (“RFP”) process and to carry out such other preconstruction activities as OPG deems necessary</td>
</tr>
<tr>
<td>Jul-2004</td>
<td>OPG Engages Hatch Mott MacDonald (“HMM”)</td>
</tr>
<tr>
<td></td>
<td>• HMM, an international tunneling / mining expert consultant company, was engaged as OPG’s Owner’s Representative (“OR”) for the Project</td>
</tr>
<tr>
<td></td>
<td>• HMM to work in association with Hatch Acres</td>
</tr>
<tr>
<td>13-Aug-2004</td>
<td>Request for Expressions of Interest (“EOI”) Issued</td>
</tr>
<tr>
<td></td>
<td>• Request for EOIs for prequalification of potential proponents issued</td>
</tr>
<tr>
<td></td>
<td>• Responses received by 09-Sep-2004 from seven companies and consortiums</td>
</tr>
<tr>
<td>Dec-2004</td>
<td>Invitation to Submit Design/Build Proposals Issued</td>
</tr>
<tr>
<td></td>
<td>• Invitations issued to four pre-qualified proponents</td>
</tr>
<tr>
<td></td>
<td>• Final Amendment (#5) issued on 26-Apr-2005</td>
</tr>
<tr>
<td>18-Feb-2005</td>
<td>Agreement Signed Between the Niagara Parks Commission (“NPC”) and OPG</td>
</tr>
<tr>
<td></td>
<td>• Agreement forms part of the larger Niagara Exchange transaction concerning the long term disposition of water rights on the Niagara River</td>
</tr>
<tr>
<td></td>
<td>• Committed OPG to undertake remedial work at the retired Ontario Power and Toronto Power generating stations for reversion of these stations to the NPC and secured the agreement of the NPC that until 2056 it would grant water rights to no party other than OPG</td>
</tr>
<tr>
<td></td>
<td>• Associated $10M settlement with Fortis Ontario, approved by the OPG Board on 08-Feb-2005, secured an irrevocable assignment of the water associated with Rankine generating station. These costs are included in the release estimate for the Project</td>
</tr>
<tr>
<td>13-May-2005</td>
<td>Design/Build Proposals Received</td>
</tr>
<tr>
<td></td>
<td>• Three (3) proposals received</td>
</tr>
<tr>
<td></td>
<td>• Proposals evaluated by separate commercial and technical teams</td>
</tr>
<tr>
<td>Jun-2005 to Jul-2005</td>
<td>Proposal Evaluation and Negotiations with Proponents</td>
</tr>
<tr>
<td></td>
<td>• Based on evaluation scores, it was determined that negotiations should proceed initially with all three proponents to determine the “best value” proposal</td>
</tr>
<tr>
<td></td>
<td>• When the proposals were re-scored after additional information was received and preliminary negotiations occurred, OPG began negotiating solely with the top two proponents</td>
</tr>
<tr>
<td></td>
<td>• At the conclusion of the process, OPG chose Strabag AG as the successful proponent</td>
</tr>
</tbody>
</table>
28-Jul-2005 | OPG Board of Directors Approves NTP Execution Phase  
• Niagara Tunnel Project approved with a budget of $985M and an in-service date of June-2010.  
• OPG Board approval subject to obtaining Provincial financing, through Ontario Electricity Financial Corporation, which was authorized on 18-Aug-2005

### Execution Phase

<table>
<thead>
<tr>
<th>Date</th>
<th>Milestone / Event</th>
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</thead>
<tbody>
<tr>
<td>18-Aug-2005</td>
<td>Design-Build Agreement (“DBA”) Signed with Strabag AG</td>
</tr>
<tr>
<td>Sept-2005</td>
<td>Strabag occupies site and starts NTP construction</td>
</tr>
</tbody>
</table>
| 17-May-2006 and 19-Jun-2006 | Strabag Issues Claims for Differing Subsurface Conditions (“DSC”) for Underwater Construction at the Intake Channel and Acceleration Wall  
• Initiation of a dispute regarding a DSC for excessive overburden on the river bed encountered during construction of the intake channel that was claimed to differ materially from the subsurface conditions described in the Geotechnical Baseline Report (“GBR”)  
• DSC claim related to work at the acceleration wall where conditions (i.e. bedrock elevation and the presence of large boulders) were claimed to differ materially from the GBR |
| 01-Sep-2006 | TBM Excavation Commences  
• TBM was acquired and assembled within 12 months according to the schedule proposed by Strabag and incorporated into the DBA |
| 23-May-2007 | Strabag Claims DSC for Adverse Conditions in the Queenston Shale  
• On or about 16-May-2007 near 840 m, immediately below the Whirlpool sandstone formation, a large block of Queenston Shale dropped from the tunnel crown  
• Strabag claimed DSC relative to the GBR |
| 20-Sep-2007 | Settlement and Release Agreements Covering the Intake Channel DSC Signed  
• Addressed DSC for the Intake Channel and Acceleration Wall underwater construction  
• Settlement Agreement signed by OPG and Strabag  
• Release Agreement signed by OPG, Strabag, Dufferin Construction and McNally Construction |
| 24-Oct-2007 | Strabag Initially Proposes a New Tunnel Alignment  
• Strabag suggested a number of benefits of realignment including an improved tunneling process |
| 05-Nov-2007 | Strabag Delivers Dispute Notice 001  
• Dispute Notice 001 delivered to OPG concerning Strabag’s DSC claim associated with “Collapse in the Tunnel Crown,” signaling their intent to refer this matter to the Dispute Review Board (“DRB”) as a complex dispute triggered by a DSC, under the process contained in DBA s 5.5(a)  
• OPG countered on 12-Nov-2007 by requesting that Strabag agree to have the DRB first decide whether DBA s 5.5(c) applies. That section states settlement of DSC’s concerning differing rock support requirements should be addressed only upon completion of the tunnel excavation |
| 04-Feb-2008 | Strabag Submits an Optimized Alignment & Revised Schedule Proposal  
• Proposal also included information on alleged DSCs, efforts to mitigate DSCs, and implications to TBM drive and costs |
<table>
<thead>
<tr>
<th>Date</th>
<th>Event Description</th>
</tr>
</thead>
</table>
| 14-Feb-2008| OPG and Strabag Senior Management Decide to Obtain a Determination from the Dispute Review Board ("DRB")  
  - Determination requested from DRB concerning the merits and materiality of DSCs alleged by Strabag  
  - DRB response would be considered by both OPG and Strabag to pursue further negotiations including finalization of commercial terms of the realignment |
| 31-Mar-2008| Ministry of Environment ("MOE") Accepts the Proposed Tunnel Realignment  
  - MOE accepts OPG request for a minor amendment to the approved EA regarding the proposed tunnel realignment |
| 04-Apr-2008| Strabag's DSC Position Summary Delivered to the DRB and OPG  
  - Initiated the DRB Hearing Process  
  - OPG and Strabag position papers, including expert reports, were subsequently exchanged and delivered to the DRB on 23-May-2008.  
  - OPG and Strabag rebuttal papers were exchanged and delivered to the DRB on 13-June-2008. |
| 23-Jun-2008 to 26-Jun-2008| DRB Hearing Held  
  - Due to the volume of materials to be considered and the complexity of the dispute, the DRB advised that their deliberations and written recommendations would likely require 60-90 days |
| 30-Aug-2008| DRB Report and Non-binding recommendations Received  
  - Report presents the DRB’s unanimous conclusions and recommendations under five topics |
| 09-Sep-2008| Strabag Commences Horizontal Realignment of Tunnel  
  - Started at approximately CH2+980 |
| Oct-2008   | OPG Management Recommends Pursuing a Negotiated Settlement with Strabag  
  - OPG evaluated options including engaging another Contractor to complete the Project and proceeding under the existing Design-Build Agreement  
  - Negotiated settlement was determined to provide the greatest likelihood of completing the Project at the lowest cost in the shortest duration |
| 11-Nov-2008| Principles of Agreement Signed  
  - Negotiations were held from 15-Oct-2008 to 17-Oct-2008 and 03-Nov-2008 to 05-Nov-2008  
  - Outlined how the Parties would reach a final resolution of Strabag’s claim of Differing Subsurface Conditions in the Queenston Formation |
| 31-Dec-2008| Strabag Starts Vertical Realignment of Tunnel  
  - Started at approximately CH3+300 |
| 09-Feb-2009| Term Sheet Signed  
  - Negotiated Term Sheet required as part of the Principles of Agreement in order to further elaborate how the Parties would finalize the Revised Agreement to complete the Niagara Tunnel Project |
| 24-Feb-2009| Agreement on Revised Contract Schedule  
  - Substantial Completion date of 15-Jun-2013 with incentives and disincentives relative to target in-service date |
| 07-Apr-2009| Agreement on Target Cost  
  - Negotiations resulted in a contract Target Cost of CAD $985M with incentives and disincentives relative to the target cost |
| 21-May-2009| OPG Board Approval  
  - Board approves the revised schedule and cost, and the amendment and execution of the Amended Design-Build Agreement with Strabag |
| 04-Jun-2009| Amended Design-Build Agreement ("ADBA") Signed  
  - Effective date of ADBA is December 1, 2008 |
### 11-Sep-2009

**Fall of Ground between 3,605m and 3,625m**
- Approximately 100 m\(^3\) of Queenston Shale and temporary tunnel lining (shotcrete, wire mesh and steel channels) fell from the right side of the tunnel crown
- Investigations concluded that a loosening of the rock support dowels put more pressure on the dowels’ face plates than they could hold, which led to the fall. Boreholes NF-4 and NF-4A contributed to the loosening of the dowels by allowing relatively fresh water to penetrate and degrade the surrounding rock
- Set back the schedule for NTP completion by approximately 17 days based on one day of delay to TBM mining translating into 0.375 days of delay to the critical path
- Final cost impact of the 2009 fall of ground was estimated at $2 M, which is equal to insurance deductible, so no claim was made.

### 30-Mar-2011

**TBM Mining Completed**
- Boring of tunnel complete
- TBM disassembly and removal follows

### 02-Jul-2011

**Fall of Ground between 6,033m to 6,080m**
- Approximately 1,200 m\(^3\) of shotcrete, steel ribs, wire mesh and loose rock fell from the tunnel crown
- Remediation costs initially estimated $17.6 M, including work done outside of the MOL mandated area, but later revised to $12.1 M. Insurer took the position that since the actual fall of ground area was less than 100 metres, a $10M claim limit applied and will pay this amount
- ADBA Target Cost will be increased by $10.4M

### 25-Jul-2012

**ADBA Amendment No. 1**
- Incorporated a number of Project Change Directives ("PCD"s), and recognized a number of PCD Deemed Amendments
- Recognized budget transfers that have occurred without change to the Target Cost or to the scope of the Work
- Amended Appendix 1.1(TTT)—Target Cost:
  - aggregate change of $90,003,566.91 to the Target Price resulting from the incorporated and recognized PCDs;
  - the revised Target Cost is about $994 M; and
  - revised allocation of the Target Cost for the purposes of cost control, cost projection and cost performances indices only.
- Amended the Substantial Completion date to 02-July-2013
- Amended Appendix 1.1(hhh) - Project Change Directive Form
- Amended Appendix 2.2(a) - Organizational Chart

### 30-Jul-2012

**Invert Concrete Lining Completed**
- Decommissioning of invert shutter was completed by 15-Aug-2012

### 19-Sep-2012

**Profile Restoration Completed**
- Decommissioning of restoration carrier/bridges was completed by 05-Oct-12

### 06-Nov-2012

**Final Concrete Lining Completed**
- Arch concrete carriers were moved to the outlet for disassembly and removal by 31-Dec-2012

### 15-Nov-2012

**Cofferdam Flooded**
- Intake stop logs were installed by 13-Nov-2012 and the cofferdam was flooded to permit removal
<table>
<thead>
<tr>
<th>Date</th>
<th>Description</th>
<th>Details</th>
</tr>
</thead>
</table>
| 04-Feb-2013| Grouting Operations Completed                                               | • Contact grouting was completed on 10-Nov-2012, and the contact grout carrier was moved to the outlet for disassembly and removal by 30-Dec-2012
• Pre-stress grouting was completed on 04-Feb-2013, and the mobile pre-stress grout carrier was removed from the tunnel by 22-Feb-2013 |
| 09-Mar-2013| Substantial Completion                                                      | After 24 hours of uninterrupted flow, the Substantial Completion milestone was achieved on 09-Mar-2013 |
| 24-July-2013| Flow Test Completed                                                         | Flow test conducted by Alden Research confirms that tunnel flow rate meets contractual Guaranteed Flow Amount of 500 m^3/s (within 2% tolerance) |
Appendix B – QA/QC Process

Niagara Tunnel Project
QA/QC Process

STRABAG
QA/QC Process
Design Review
Quality Audits
Inspection & Testing
Vendor Surveillance
Identify Trends
Corrective/Preventative Actions

Items out of specification

STRABAG Identify Nonconformance

STRABAG Issue NCN
Appendix A provides details (i.e. description, cause, proposed remedial actions)

OR Quality Monitoring
Measurements (joint)
Documentation (e.g. Daily Construction Reports, Checklists, QA/QC Audits)
Identify Trends

OR Identify Nonconformance

OPG/OR May Issue
Disallowed Cost Notice (DCN)
or Disallowance Advisory (DA)

OR Review NCN
Accept
Return to Revise & Resubmit

OR Complete NCN Appendix B

OR Verify Satisfactory Completion

OR Update NCN Log

STRABAG Complete Corrective Action
Accept
Repair
Regrade
Rework
Scrap

STRABAG Verify Completed Action
Complete Appendix A Verification

STRABAG Close NCN

STRABAG Issue QA/QC Monthly Report

OR Review & Comment on STRABAG QA/QC Monthly Report

OR Summarize QA/QC Information & Transmit to OPG*
Monthly Report
QA/QC Meeting Notes
NCNs
NCN Log

OPG Review & Analyse Summarized QA/QC Information
Update OPG QA/QC Database
Assess trends
Provide feedback to OR

*Note: Refer to Table 1 for transmittal frequency
### Appendix C – Key Risk Plan

**Niagara Tunnel Project Key Risk Plan**

<table>
<thead>
<tr>
<th>ID</th>
<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Major Tunnel Boring Machine (TBM) breakdown including main bearing failure</td>
<td>- Proactive maintenance program for the TBM and associated equipment&lt;br&gt; - Maintenance 8hr shift/day&lt;br&gt; - Regular oil sampling and testing&lt;br&gt; - Regular inspections by remote camera&lt;br&gt; - 10% L10 life with sufficient safety factor for main bearing&lt;br&gt; - Regular inspections and remote monitoring of main bearing&lt;br&gt; - Procurement of spare main bearing and storage in Ohio&lt;br&gt; - 24-hour servicing by experienced workforces including TBM manufacturer&lt;br&gt; - Adjustment of Fleet during mixed face boring conditions</td>
<td>Monitoring mitigation:&lt;br&gt; - OPG and OR monitoring of spare-main bearing availability&lt;br&gt; - OPG and OR monitoring of TBM availability&lt;br&gt; - Off monitoring of oil sampling and testing&lt;br&gt; Monitoring the risk:&lt;br&gt; - On-going OR monitoring of TBM performance&lt;br&gt; Performance metrics/ early warning signals:&lt;br&gt; - Oil analysis results, oil temperature, oil filter plugging&lt;br&gt; - Oil analysis results, oil temperature, oil filter plugging</td>
<td>If this risk occurs:&lt;br&gt; - Replace main bearing&lt;br&gt; - Overall project contingency is $164M.&lt;br&gt; - Project contingency will be drawn down to fund costs associated with this risk&lt;br&gt; - Adjustments to Target Cost and Contract Schedule are identified in Appendix 5.3C</td>
<td>Risk Owner: Strabag / OPG Oversight</td>
</tr>
<tr>
<td>2</td>
<td>Main conveyor failure</td>
<td>- Metal detection, contingency planning, keep critical spare parts and belts on site&lt;br&gt; - Video monitoring cameras to conveyor belt in particular at transfer points&lt;br&gt; - Increased visual monitoring&lt;br&gt; - Proper TBM operation&lt;br&gt; - Qualified supervisors and maintenance crew&lt;br&gt; - Conveyor structural (rollers) inspection</td>
<td>Monitoring mitigation:&lt;br&gt; - OPG and OR monitoring of conveyor belt monitoring&lt;br&gt; Monitoring the risk:&lt;br&gt; - [Tbd]</td>
<td>Financial Impact ($):&lt;br&gt; - $300k</td>
<td>Risk Owner: Strabag / OPG Oversight</td>
</tr>
<tr>
<td>3</td>
<td>Inundation of tunnel</td>
<td>- Cofferdam designed for 30 year return&lt;br&gt; - Valve that allows water ing to be locked out&lt;br&gt; - 300m long tunnel has been excavated&lt;br&gt; - Adequate emergency (checked by Contractor and reviewed by OR)&lt;br&gt; - Close contact and cooperation with INCW operators&lt;br&gt; - Monitoring system implemented and reviewed by designer&lt;br&gt; - Regular inspections by Engineer&lt;br&gt; - Maintenance plan for extended life&lt;br&gt; - Adequate pumping capacity</td>
<td>Monitoring mitigation:&lt;br&gt; - Probability: &lt;br&gt; - Management considerations</td>
<td>Financial Impact ($):&lt;br&gt; - $0</td>
<td>Risk Owner: Strabag / OPG Oversight</td>
</tr>
</tbody>
</table>
### Niagara Tunnel Project Key Risk Plan

#### ID: R01

<table>
<thead>
<tr>
<th>ID</th>
<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Critical marine work impeded by marine operational constraints at the INCW</td>
<td>Plan the cofferdam removal to minimize the amount of marine activity required. Plan cofferdam removal to avoid ice season (December 15 to April 30)</td>
<td></td>
<td>OPS 2009 Quantitative analysis</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Assumptions:</td>
<td></td>
<td>Probability: 0.5</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>Financial Impact ($): none</td>
<td></td>
<td>Financial impact (days): 30, 60, 90 (worst)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Schedule Impact (days): 30, 60, 90 (worst)</td>
<td></td>
<td>Schedule impact (days):</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Assumptions:</td>
<td></td>
<td>Assumptions:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Operational constraints defined in ADBA - Appendix 1.1 (Constraints)</td>
<td></td>
<td>Assumptions:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Risk expires when cofferdam is removed</td>
<td></td>
<td>Assumptions:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tunnel collapse</td>
<td>Extensive geotechnical investigations</td>
<td></td>
<td>Comments: Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $156M.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Adequate design/construction QA/QC plan</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Independent design reviews by Contractor and OR</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>On-site full time presence by tunnel designer</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Design and adjustments as required during construction</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Tunnel instrumentation and monitoring of rock support</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Material testing (rock dowels, shotcrete)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Convergence monitoring and regular review of results by geotechnical engineer, construction manager and designer</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Assumptions:</td>
<td></td>
<td>Assumptions:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Risk expires when gates at tunnel intake are in place</td>
<td></td>
<td>Assumptions:</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- Risk Owner & SME: Strabag / OPG Oversight
- SME: K. Child
- Overall project contingency is $156M.
- Risk assessed as part of 2009 quantitative analysis.

**Assumptions:**
- Worst case: everything floods. Flood TBM, Invert carrier, and Arch carrier. 8 weeks to repair cofferdam, 4 months to dewater (need to procure pumps and deliver).
- No loss of life.
- Insurance covers equipment and materials repair.
- PROBABILITY
- FINANCIAL IMPACT
- SCHEDULE IMPACT
- MANAGEABILITY
- IMMINENCE
- Probability: 0.5
- Financial Impact ($): none
- Schedule Impact (days): 30, 60, 90 (worst)
- IMMINENCE
- Schedule impact (days):
## Niagara Tunnel Project Key Risk Plan

### ID #1: Fatalities

**Assumptions:**
- Risk expires when tunnel construction is complete.
- Early engagement of Independent Electricity System Operator (IESO) to understand consequences of risk plug outage and improve chance of getting outage when it is needed.
- Communicate request for flexibility to IESO as soon as possible, especially once in the 18 month Outage Reference Planning window.
- The Niagara Plant Group Planning Office scheduled the PGS (PG1- PG6) outage for Monday, June 3 to Sunday, June 16. This date was included in the data used for the Niagara Plant Group Business Plan 2010-2014.

**OPG 2009 Quantitative analysis**
- Probability: 0.05
- Financial Impact: $1-10M
- Schedule Impact: 30-90-180 days

**Assumptions:**
- Source of delay comes from IESO. Note: IESO they think the rock plug removal would be required. Spring or fall might be easier to get an outage from IESO since there could be less demand; however system status could be a factor (e.g. nuclear station vacuum building outage).
- Assume a bonus of $200k per day for Contractor.

**Probability:**
- Financial Impact ($): 
- Schedule Impact (days): 

**Comments:**
- Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M.
- Assumptions:

**Risk Owner & SME:**
- Risk Owner: Strabag / OPG Oversight
- SME: K. Child

### ID #2: Delays in providing outage for rock plug removal

**Assumptions:**
- According to schedule risk starts April 2013 and expires June 2013 (water-up procedure).

**OPG 2009 Quantitative analysis**
- Probability: 0.5
- Financial Impact: none
- Schedule Impact: 5-10-30 days

**Assumptions:**
- Source of delay comes from IESO. IESO doesn't think rock plug removal is necessary if they think the rock plug removal would be required. Spring or fall might be easier to get an outage from IESO since there could be less demand; however system status could be a factor (e.g. nuclear station vacuum building outage).
- Assume a bonus of $200k per day for Contractor.

**Probability:**
- Financial Impact ($): 
- Schedule Impact (days): 

**Comments:**
- Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M.
- Assumptions:

**Risk Owner & SME:**
- Risk Owner: Strabag / OPG Oversight
- SME: K. Child

### ID #3: Prototype overbreak infill operation prolongs schedule

**Assumptions:**
- Planned learning curve via slow initial progress rate
- Property designed system
- Detailed work preparation and scheduling
- Remediation: Timely modifications to improve the efficiency of the infill operation. This will be achieved by using a mobile equipment to install rock anchors, wire mesh, ribs and shotcrete and to complete consolidation grouting. This work is taking place in the areas of the most extensive overbreak.

**Probability:**
- Financial Impact ($): 
- Schedule Impact (days): 

**Comments:**
- Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M.
- Assumptions:

**Risk Owner & SME:**
- Risk Owner: OPG Oversight
- SME: R. Everdell

### ID #4: Profile restoration operation prolongs schedule

**Assumptions:**
- Establishment of trigger levels for maximum allowed deformation
- Emergency rescue and evacuation plan in place
- Fully installable membranes
- Detailed monitoring of liner convergence during pre-stressing
- Test tube planned for contact and pre-stress grouting
- Insurance in place (Transfer Risk to Insurance)
- Remediation: Repair and restore tunnel

**OPG 2009 Quantitative analysis**
- Probability: 0.05
- Financial Impact: $1-10M
- Schedule Impact: 30-90-180 days

**Assumptions:**
- Localized collapse of tunnel (of 10-20m) that damages major equipment (i.e. TBM, invert carrier, conveyor, ventilation, etc.)
- Insurable event with $1M deductible. Worst case: collapse of temporary liner since permanent liner collapse would lead to more localized collapse.
- Insurance deductible for P5.

**Probability:**
- Financial Impact ($): 
- Schedule Impact (days): 

**Comments:**
- Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M.
- Assumptions:

**Risk Owner & SME:**
- Risk Owner: OPG
- SME: R. Everdell

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10/15/2012  Page 3 of 10

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<table>
<thead>
<tr>
<th>ID</th>
<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Construction</td>
<td>Assumptions: Risk starts September 2009 and expires at completion of profile restoration</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Assumptions:</td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>Concurrent activities delay progress</td>
<td>Overall progress delayed due to logistics of concurrent construction operations (i.e. TBM mining, invert concrete, Profile restoration, Arch concrete and Grouting)</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Consequences: Delay in construction Assumptions: Risk decreases in April 2011 when TBM mining complete</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Assumptions:</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>10/15/2012</td>
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</tr>
</tbody>
</table>
### Niagara Tunnel Project Key Risk Plan

#### R01

<table>
<thead>
<tr>
<th>ID</th>
<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>#11</td>
<td>Non-conformance and/or non-compliance is identified and requires rework</td>
<td>Permanent works defective or do not conformance with specifications due to construction quality (includes permanent works concrete deficiencies) Consequences: Cost and delay in construction related to rework Assumptions: Risk starts when tunnel final lining commences and ends when pre-drilling is complete</td>
<td>Full-time OR presence during construction Structured submittal and design review process by OR and Strabag Monitoring construction works against plan (OR and Strabag) OR regularly reviews Contractor’s formal non-conformance process in QC reports Any non-conformance required to have a full time Quality Assurance manager according to ADBA OPG/OR gives Contractor Disallowance Advisory notices to notify Contractor that all costs arising from future occurrences of specific actions, omissions or occurrences would be disallowed costs</td>
<td>Probability: 0.5 Financial Impact ($): 3 Schedule (days): none Assumptions: Worst case: repairing concrete, excavating localized areas of concrete lining and membrane (e.g., aggregate of 25m) because of sub-standard concrete/thickness, etc. Concrete placement at $40,000 per m and removal $20,000 per m. Assumes all non-conformances/non-compliances are detected. Quality concerns discovered during operation are outside the scope of this analysis. Assume no schedule delay at this burn rate. Contract: Adjust target structure is removed and no problem is found.</td>
<td>Comments: Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. Assumptions: Worst case: unexpected ground conditions (e.g. sidewalls spalling affecting gripper efficiency). Frequency and magnitude of occurrence are captured in P95. Assume no schedule delay at this burn rate. Target date extended due to claims.</td>
<td></td>
</tr>
<tr>
<td>#12</td>
<td>Contract management problems increases project costs</td>
<td>Project costs increase due to contract management problems (including claims and oversight of Contractor) Consequences: Cost increase Assumptions: Risk expires one year after project completion (1 year limitation on claims)</td>
<td>Use of detailed project procedures OPG conducting intermittent audits (e.g. Cost Control Audits) Contractor’s books of accounts and financial statements under the ADBA are fully open to OPG Well defined contract language around disallowed costs Adequate contract language to define Contractor’s obligations, Adequate and proactive Owner oversight</td>
<td>Probability: 0.3 Financial Impact ($): 5 Schedule (days): none Assumptions: Worst Case: unexpected ground conditions (e.g. soil and rock spalling affecting gripper efficiency). Frequency and magnitude of occurrence are captured in P95. Assume no schedule delay at this burn rate. Target date extended due to claims.</td>
<td>Comments: Risk assessed as part of 2009 quantitative analysis. Overall project contingency is $164M. Assumptions:</td>
<td></td>
</tr>
</tbody>
</table>
### Niagara Tunnel Project Key Risk Plan

<table>
<thead>
<tr>
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<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
<th>Risk Owner &amp; SME</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ID#18)</td>
<td>Contractor defaults on its obligations</td>
<td>Contractor abandons project due to potential for significant loss</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Consequences: Cost and delay in construction - to be addressed through a superseding business case.</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Assumptions:</td>
<td>Risk expires at project completion</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(ID#18)</td>
<td>Contractor defaults on its obligations</td>
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<td></td>
<td>Consequences: Cost and delay in construction - to be addressed through a superseding business case.</td>
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<td></td>
</tr>
<tr>
<td>Assumptions:</td>
<td>Risk expires at project completion</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>(ID#19)</td>
<td>Excessive convergence delay installation of final lining</td>
<td>Ground convergence exceeding specifications delays installation of the final concrete lining due to ground conditions and/or inadequate support</td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>Consequences: Damage to tunnel, damage to/and loss of equipment, delay in construction, and personnel injuries and/ or fatalities.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assumptions:</td>
<td>Risk expires when tunnel construction is complete</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(ID#20)</td>
<td>Fire damages tunnel, equipment, and materials</td>
<td>Fire in the tunnel due to hot works, faulty equipment, overheating, flammable gases and liquids and open flames and smoking</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>Consequences: Damage to tunnel, damage to/and loss of equipment, delay in construction, and personnel injuries and/ or fatalities.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assumptions:</td>
<td>Risk expires when tunnel construction is complete</td>
<td></td>
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</tbody>
</table>

**Quantitative Analysis**

- **Probability**: 
  - Probability:  
  - Schedule Impact (days): 
  - Financial Impact ($): 
  - Manageability: 
  - Imminence: 

**Quantitative Analysis**

- **Probability**: 
  - Probability:  
  - Schedule Impact (days): 
  - Financial Impact ($): 
  - Manageability: 
  - Imminence: 

**Quantitative Analysis**

- **Probability**: 
  - Probability:  
  - Schedule Impact (days): 
  - Financial Impact ($): 
  - Manageability: 
  - Imminence: 

**Quantitative Analysis**

- **Probability**: 
  - Probability:  
  - Schedule Impact (days): 
  - Financial Impact ($): 
  - Manageability: 
  - Imminence: 

**Notes**

- Comments: 
  - Project would be re-evaluated and addressed through a superseding release of funds. 
- Assumptions:

**Notes**

- Comments: 
  - Project would be re-evaluated and addressed through a superseding release of funds. 
- Assumptions:

**Notes**

- Comments: 
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- Assumptions:

**Notes**

- Comments: 
  - Project would be re-evaluated and addressed through a superseding release of funds. 
- Assumptions:

**Notes**

- Comments: 
  - Project would be re-evaluated and addressed through a superseding release of funds. 
- Assumptions:
# Niagara Tunnel Project Key Risk Plan

## Risk ID: #23
### Significant environmental incident during Owner Only Project
- **Owner & SME**: Strabag / OPG Oversight
- **SME**: C. Mee

**Risk Description**: Major environmental regulatory infraction due to a reportable spill or discharge that results in a major environmental regulatory infraction or under a municipal by-law.

**Consequences**: Regulatory orders and charges, third party actions, and reputational damage

**Assumptions**:
- Risk expires when tunnel construction is complete
- Transferred to Strabag via Amended Design Build Agreement (ADBA)
- OPG is Owner Only. Contractor is required to comply with all applicable statutes and regulatory requirements relating to discharges to the environment.
- ADBA requires Strabag to comply with applicable laws and the Environmental Management Plan.
- ADBA specifies Contractor's environmental reporting requirements. The Contractor is responsible for reporting its discharges to the regulator, as required and to OPG.
- OPG and OR reviewing Strabag environmental reports and audits
- Residual risk includes impact to OPG's corporate reputation

**Quantitative Analysis**:
- **Probability**: *  
- **Financial Impact ($)**: *  
- **Schedule Impact (days)**: *  
- **Imminence**: *  
- **Manageability**: *  

**Notes**: Comments:  
Assumptions: *

## Risk ID: #24
### Significant safety incident during Owner Only Project
- **Owner & SME**: Strabag
- **SME**: K. Child

**Risk Description**: Major safety incident due to construction related accident or work stoppage.

**Consequences**: Regulatory orders and charges, personnel injuries and/or fatalities, and reputational damage

**Assumptions**:
- Risk expires when tunnel construction is complete
- Transferred to Strabag via Amended Design Build Agreement (ADBA).
- Amended Design Build Agreement requires Strabag to comply with applicable laws and implement the Project Specific Site Safety, Security, Public Safety, and Emergency Response Plan.
- Design Build Agreement specifies Strabag’s safety reporting requirements.
- Design Build Agreement requires Strabag to maintain workers compensation coverage.
- OR issues Safety observations.
- OPG and OR monitoring of safety reports.
- Residual risk includes impact to OPG's corporate reputation.

**Quantitative Analysis**:
- **Probability**: *  
- **Financial Impact ($)**: *  
- **Schedule Impact (days)**: *  
- **Imminence**: *  
- **Manageability**: *  

**Notes**: Comments:  
Assumptions: *
### Niagara Tunnel Project Key Risk Plan

#### ID #38: Fall of ground incident
- **Risk**: Fall of ground due to inadequate design and/or construction of ground support and inadequate monitoring of convergence and support condition
- **Consequences**: Damage to tunnel, damage to and/or loss of equipment, delay in construction, cost increase, and personnel injuries and/or fatalities
- **Assumptions**:
  - Knowledge gained from fall of ground event at 3+610
  - Clearly defined monitoring protocol
  - Monitoring of ground movement by designer
  - Full time geotechnical engineer and designer on site
  - Detailed analysis and review of monitoring results
  - Tunnel instrumentation and monitoring of risk support
  - Mobile equipment with sufficient reach available on site for installation of additional rock support
  - Remediation: Perform remedial work to restore initial tunnel lining

#### ID #39: Failure in arch concrete system
- **Risk**: Arch concrete progress delayed due initial set up delays and equipment failures during on-going operation
- **Consequences**: Cost and delay in construction
- **Assumptions**:
  - Training of personnel, adequate supervision and regular preventative maintenance
  - Typical tunnel formwork system
  - Critical spare parts on site
  - Contingencies for all critical equipment in place

#### ID #40: Pre-stress grouting prolongs schedule
- **Risk**: Pre-stress grouting progress delayed due initial set up delays and scale of operations
- **Consequences**: Cost and delay in construction
- **Assumptions**:
  - Extensive design and input from grouter
  - Discussions with third-party designers and owners that have used this technique
  - OR review of design
  - OR monitoring of construction
  - Trial sections of tunnel to finalize application of method
<table>
<thead>
<tr>
<th>ID</th>
<th>Risk</th>
<th>Mitigation Detail</th>
<th>Residual Risk</th>
<th>Quantitative Analysis</th>
<th>Notes</th>
</tr>
</thead>
</table>
| #41 | Swelling in the invert | Swelling of ground in the tunnel invert at the low point due to exposure to water  
Consequences: Cost in construction  
Assumptions: |  |  |  |
| #42 | Loss of key project personnel | Loss of key project personnel due to length of project  
Consequences: Cost and delay in construction  
Assumptions: |  |  |  |
| #44 | Concrete delivery problems delay progress of final lining | Concrete delivery problems delay progress of final lining due to the lack of a reliable off-site concrete supply that meets required specifications  
Consequences: Cost and delay in construction  
Assumptions: |  |  |  |
Niagara Tunnel Project Key Risk Plan

Risk Attributes

<table>
<thead>
<tr>
<th>Probability</th>
<th>Low probability (&lt; 10%)</th>
<th>Medium probability</th>
<th>High probability (&gt; 70%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(the probability that a risk will occur)</td>
<td>1 (Low)</td>
<td>2 (Medium)</td>
<td>3 (High)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Financial Impact</th>
<th>The risk will have negligible financial impact on the Project (e.g. &quot;risk is easily absorbed by the Project budget&quot;)</th>
<th>The risk will have a notable financial impact on the Project (e.g. &quot;additional funds would be required by the Project&quot;)</th>
<th>The risk endangers the financial viability of the Project (e.g. &quot;significant impact on the Project business plan&quot;)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(the financial consequences of a risk should it occur)</td>
<td>1 (Low)</td>
<td>2 (Medium)</td>
<td>3 (High)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Schedule Impact</th>
<th>The risk will have little or no Project schedule impact (delay tasks within their available free float)</th>
<th>The risk will have a notable Project schedule impact (delay one or more tasks on the critical path)</th>
<th>The risk will have a significant impact on the Project schedule (Project in-service date would be delayed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(the impact that a risk would have on the schedule, and more importantly overall project duration, should it occur)</td>
<td>1 (Low)</td>
<td>2 (Medium)</td>
<td>3 (High)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Manageability</th>
<th>The Project will have no difficulty controlling or influencing the outcome of the risk (e.g. &quot;risk easily handled by the Project’s managed system&quot;)</th>
<th>The Project will have some difficulty controlling or influencing the outcome of the risk</th>
<th>The Project will be unable to control or influence the outcome of the risk (e.g. “no change to the risk regardless of what the Project does”)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(the degree to which the Project is able to control the risk)</td>
<td>1 (Low)</td>
<td>2 (Medium)</td>
<td>3 (High)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Imminence</th>
<th>The risk is expected or predicted to occur in the long term (after 18 months)</th>
<th>The risk is expected or predicted to occur within the medium term (between the next 6 to 18 months)</th>
<th>The risk is expected or predicted to occur within the short term (within next 6 months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(the nearness in time at which the risk is expected or predicted to occur.)</td>
<td>1 (Low)</td>
<td>2 (Medium)</td>
<td>3 (High)</td>
</tr>
</tbody>
</table>
# Appendix D – Lessons Learned

<table>
<thead>
<tr>
<th>ID</th>
<th>Category</th>
<th>Issue</th>
<th>Problem/Success</th>
<th>Impact</th>
<th>Recommendation</th>
<th>Additional OPG Comments/Actions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Schedule</td>
<td>Time-way (linear) schedule.</td>
<td>Success - Excellent tracking and communication tool for a linear project.</td>
<td>Allowed the Project team, stakeholders, and sponsor to understand both progress and performance.</td>
<td>Although OPG carries out a limited number of linear projects, it could consider employing this format on other types of projects. Project team should document the Time-Way Scheduling process and any lessons learned to share with other project teams.</td>
<td>None.</td>
</tr>
<tr>
<td>2</td>
<td>Cost</td>
<td>BCS cost broken out by month in a defined work breakdown structure.</td>
<td>Success - Able to monitor against the baseline.</td>
<td>More accurate tracking/forecasting.</td>
<td>Projects should have a detailed cost broken out by month in advance of project release.</td>
<td>None.</td>
</tr>
<tr>
<td>3</td>
<td>Cost</td>
<td>Forecasting model.</td>
<td>Success - Development of a detailed forecasting model.</td>
<td>Ability to forecast final completion cost quickly after month end.</td>
<td>Projects should have a forecasting model developed in order to forecast final costs based on current month actuals.</td>
<td>None.</td>
</tr>
<tr>
<td>4</td>
<td>Scope</td>
<td>Disposal of surplus goods.</td>
<td>Problem - Unclear language in the ADBA with respect to: 1) Owner/Contractor roles in the Disposal of Surplus Goods Process, and Inefficient use of resources (OPG, Owner's Rep, &amp; Contractor) with numerous revisions of plans required.</td>
<td>Clear contract language that identifies OPG’s expectations to optimize the net value recovered. Use of an unreserved auction was effective for a project of this size.</td>
<td></td>
<td>None.</td>
</tr>
<tr>
<td>ID</td>
<td>Category</td>
<td>Issue</td>
<td>Problem/Success</td>
<td>Impact</td>
<td>Recommendation</td>
<td>Additional OPG Comments/Actions</td>
</tr>
<tr>
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</tr>
<tr>
<td></td>
<td></td>
<td>2) Method of disposal.</td>
<td></td>
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<td>5</td>
<td>Scope</td>
<td>Identification of Plant Group wants/needs.</td>
<td>Problem - It was difficult for the Plant Group to identify all of their requirements from the concept drawings</td>
<td>Uncertainty about the end product (i.e. intake fencing, parking lot, fall arrest, etc.).</td>
<td>Involve appropriate stakeholders early in the project. The Plant Group needs to be provided sufficient time and resources to document what they want and the rationale. Dedicated resources should be considered.</td>
<td>None.</td>
</tr>
<tr>
<td>6</td>
<td>Quality</td>
<td>Owner requirements/ expectations and inadequate division of responsibilities.</td>
<td>Problem - Owner has limited input on Contractor's resource allocation to: QA, QC, Health &amp; Safety, and Environment (i.e. production employees were responsible for quality control).</td>
<td>Owner requirements/ expectations in these areas not met. Production overrides quality - conflict of Contractor's priorities. Quality control was impacted.</td>
<td>Design-Build contracts should contain Owner's requirement for Contractor site positions, numbers, disciplines, and qualifications. If quality control is to be properly enforced by the contractor, a clear division/separation of the role must be made. Having production employees responsible for quality typically does not work. Independent management (i.e. 3rd party) of Quality is a</td>
<td>Further assessment of OPG contracting model/terms - emphasize inclusion of project-specific and/or OPG standards in the areas of safety, environment, &amp; quality (SEQ).</td>
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<td>Better (recommended) approach for priority management.</td>
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<td>7</td>
<td>Quality</td>
<td>Issue management.</td>
<td>Problem - Reactive approach taken by Contractor to resolve technical/construction issues. Root cause analysis not performed by Contractor.</td>
<td>Cost and schedule impact.</td>
<td>In tunneling, the premise to battle through existing situations/conditions is the norm. Fixing a problem when it is encountered should be given greater consideration (i.e. overbreak, excessive construction water). Also, proceeding with work that does not have a submittal or has a submittal without an ‘acceptable status’ should not occur (i.e. overbreak restoration).</td>
<td>A more robust contingency planning process (by the contractor) to incorporate root cause techniques to support problem resolution of construction/technical issues.</td>
</tr>
<tr>
<td>8</td>
<td>Quality</td>
<td>Method Statements.</td>
<td>Problem - Contractor did not utilize method statements effectively.</td>
<td>Education by OR required.</td>
<td>Method Statements are an effective tool if taken seriously and prepared with the intent of being utilized and not just to satisfy a Project/Contract requirement.</td>
<td>Provide Method Statement templates/examples that clearly outline expectations of Contractor.</td>
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<td>9</td>
<td>Human Resources</td>
<td>Consistent staffing.</td>
<td>Problem - There were significant staff changes in the Plant Group engineering and management ranks as a result of the long duration of the project.</td>
<td>No real buy-in/alignment from Plant Group staff to review/comment on any drawings circulated.</td>
<td>No recommendation - it is difficult to allocate OPG production and engineering staff on a project for 8 years.</td>
<td>None.</td>
</tr>
<tr>
<td>10</td>
<td>Human Resources</td>
<td>Team building.</td>
<td>Success - A team-building event held at the beginning of the project allowed all parties (Contractor &amp; key subcontractors, OPG, OR) to get to know each other on a personal basis.</td>
<td>This opened the lines of communication and assisted in building trust between parties which allowed resolutions to be achieved on a shorter timeline.</td>
<td>Whether it is an organized team building event or simply a summer barbecue, these events should be held on a regular basis throughout the life of the project.</td>
<td>None.</td>
</tr>
<tr>
<td>11</td>
<td>Human Resources</td>
<td>Dedicated core project team.</td>
<td>Success - core OPG/OR project team remained dedicated to the Project.</td>
<td>Consistency and limited knowledge transfer loss.</td>
<td>Start out with key players and bring on people as needed.</td>
<td>None.</td>
</tr>
<tr>
<td>12</td>
<td>Communications</td>
<td>Use of tables and bullets in the monthly report.</td>
<td>Success - Although making the monthly report somewhat longer, the use of table and bullet formatting in various sections of the report made the detail contained in the monthly report more visible and comprehensive.</td>
<td>Improved communications.</td>
<td>Share NTP monthly report template with the HTO PMO to make it available for other projects.</td>
<td>None.</td>
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<tr>
<td>13</td>
<td>Communications</td>
<td>Community Impact Agreement (CIA) &amp; Liaison Committee.</td>
<td>Success - Forecast impacts of the Project on the host communities were proactively addressed.</td>
<td>Compensation payments permitted host municipalities to address significant local concerns in advance and the Liaison Committee promoted ongoing dialogue to limit community issues throughout Project execution.</td>
<td>Adopt similar agreements &amp; procedures with host communities where warranted by project scale &amp; potential community impacts.</td>
<td>None.</td>
</tr>
<tr>
<td>14</td>
<td>Communications</td>
<td>Communication management.</td>
<td>Problem - Information was not consistently being cascaded to the site-level. Miscommunication with external stakeholders.</td>
<td>OPG reputation. Project cost and schedule.</td>
<td>Ensuring the most recent/accurate information is available to those that require it. Too often information is not shared and by the time it reaches the level where it is required it is either too late or inaccurate. Sharing information is a key to success.</td>
<td>Incorporate Contractor into overall project communication matrix. Contractor discipline / management system issue.</td>
</tr>
<tr>
<td>15</td>
<td>Communications</td>
<td>Partnering approach / teamwork.</td>
<td>Success - All parties eventually 'bought into' the partnering concept even though the Contractor was very silo'd (internally).</td>
<td>Effective teamwork and cooperation by external stakeholders.</td>
<td>If a partnering concept is established early in the project, it can be extremely effective. Effective partnering requires 'give-and-take' on both sides. Having divided sectors which may have individual</td>
<td>OPG's code of conduct and expense policies may restrict team building opportunities with external contractors and forego the benefits.</td>
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<td>16</td>
<td>Risk</td>
<td>Comprehensive risk review meetings.</td>
<td>Success - The diverse attendance of key project management and construction staff allowed for productive risk review meetings (monthly reviews and analysis meetings).</td>
<td>Proactive risk management with risk definition and risk response actions evolving over the life of the project.</td>
<td>Commercial terms and conditions with installation contractors, design contractors, and owner's engineer should stipulate involvement of all parties in co-operative risk management activities.</td>
<td>Emphasize ‘shared’ risk register approach.</td>
</tr>
<tr>
<td>17</td>
<td>Risk</td>
<td>Combined risk management process was required by underwriters of the Builders All-Risk Insurance.</td>
<td>Success - It promoted collaboration between the contractor, owner, &amp; owner's rep in the identification and management of the majority of the significant Project risks.</td>
<td>Strong communication amongst all parties concerning design &amp; construction risks ensuring clear understanding of risks, appropriate mitigation, &amp; clear establishment of accountabilities.</td>
<td>Where warranted by project scale &amp; risks, adopt combined risk management process ensuring owner / contractor collaboration on risk management during execution of future OPG projects.</td>
<td>Share this practice with other HTO PMO Clients at a future quarterly PMC meeting.</td>
</tr>
<tr>
<td>18</td>
<td>Risk</td>
<td>Format of the risk registers.</td>
<td>Problem - Original risk registers were populated in Excel format. Became cumbersome to review.</td>
<td>Less efficient meetings.</td>
<td>Populate risk registers in a database format to allow for easier sorting / review of risks and tracking of changes.</td>
<td>Look at using established commercial software for this on future projects.</td>
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<td>19</td>
<td>Risk</td>
<td>Attempt to transfer risk through fixed price.</td>
<td>Problem - Design-build lump-sum contract model gives the Owner the expectation of risk acceptance by the Contractor even though the risk has not been adequately assessed or priced. Risks that are not identified and allocated become disputes.</td>
<td>Project may not have had sufficient overall cost allocation (contingency) to cover risks. False sense of security in reporting to corporate oversight.</td>
<td>Risk assessment must start before the contract stage, be thorough and documented. Allocation of risk must be addressed in the contract.</td>
<td>None.</td>
</tr>
<tr>
<td>20</td>
<td>Procurement</td>
<td>Contracting strategy - Fixed-price contract inappropriate for projects with significant site-specific underground or geotechnical risks.</td>
<td>Problem - Significant geotechnical risk that Design-Build contractor never accepted. Conditions were more adverse than the baseline which resulted in claims / disputes. Contractor cannot absorb significant losses (without potential for recovery on future work).</td>
<td>Increased costs and schedule delays due to significant work/time to: (i) resolve disputes, and (ii) renegotiate the contract.</td>
<td>Forego fixed price where geotechnical risks are high and match contracting strategy to risk profile. Use target cost approach with incentives/disincentives to optimize risk transfer to contractors.</td>
<td>Consider utilization of the CII PDCS tool.</td>
</tr>
<tr>
<td>21</td>
<td>Procurement</td>
<td>Contract renegotiation.</td>
<td>Success - Renegotiated Target Price Contract was accurate with no cost or schedule overruns over a period of four years.</td>
<td>There was a shared ownership of cost and schedule and more awareness of Owner’s risk.</td>
<td>Better model for underground works than fixed price.</td>
<td>None.</td>
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<td>22</td>
<td>Integration</td>
<td>Owner's Rep. and OPG (Project Management and Law) coordination of Project changes and risk management.</td>
<td>Success - Very successful integration of Owner's Rep. and OPG (Project Management and Law) efforts related to the drafting, review, and signoff of PCD's.</td>
<td>Well-defined roles resulted in effective management of Project risks and changes - best practices in team integration employed.</td>
<td>Project management teams employing external Owner's Rep.'s should reference NTP - reflects an excellent use of personnel and resources and effective time management as well as risk mitigation practices. Best practices employed with very successful results.</td>
<td>None.</td>
</tr>
<tr>
<td>23</td>
<td>Technical / Design</td>
<td>Original contract did not require full-time design representative at site. Requirement added when Amended Design-Build Agreement (ADBA) was negotiated.</td>
<td>Problem - Initial problems with construction QC and interpretation of design when design rep. was not on site.</td>
<td>QC and engineering issues leading to delay and rework (cost and schedule impact).</td>
<td>When using the Design-Build project delivery model, the Contractor should be required to have a design representative on site full-time during construction.</td>
<td>None.</td>
</tr>
<tr>
<td>24</td>
<td>Technical / Design</td>
<td>Lack of technical and procurement expertise allocated to the Project by the Design-Build contractor.</td>
<td>Problem - Design-Build contractors tend to focus resources on the areas of the work where the company has expertise (i.e. contractor focus on tunnelling to the</td>
<td>Lack of management and coordination of subcontracts leads to cost over-runs, quality issues and schedule over-runs.</td>
<td>Design-Build contracts should contain Owner's requirement for site positions, numbers, disciplines, and qualifications.</td>
<td>None.</td>
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<td>ID</td>
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<td>25</td>
<td>Technical / Design</td>
<td>Resolution of problems.</td>
<td>Success - Major problems were overcome by OPG, the Owner's Rep., and the Contractor working together harmoniously and pragmatically</td>
<td>Timely resolution of problems.</td>
<td>In part this was made possible by scoring and choosing the correct Contractor during proposal evaluations.</td>
<td>None.</td>
</tr>
<tr>
<td>26</td>
<td>Business Processes</td>
<td>Signing authorities for contract changes - same level of signing authority for changes as in the original contract.</td>
<td>Problem - Difficult to obtain executive level signatures. Numerous change orders over life of contract and some were of insignificant value or had no impact on cost or schedule envelopes.</td>
<td>Slows down the change management process; requires unnecessary legal input because of 'high level signature'.</td>
<td>Reconsider OPG OAR policy given success with revised DBA precedent that permits flexible contract administration - low cost (under $100K) and no schedule changes within approved cost and schedule envelopes do not require signing by EVP levels; set-up specific project authorities tailored to the project.</td>
<td>Include detailed descriptions on PCD's.</td>
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<td>27</td>
<td>Project Controls</td>
<td>Inadequate inventory management by the Contractor.</td>
<td>Problem - Difficulty in substantiating the value of goods in inventory at the time of contract conversion to target-price and substantiating the value of surplus goods at disposition (i.e. scrap/write-off, transfer or sale).</td>
<td>Reputational risk for OPG concerning inadequate controls, risk of inability to recover unsubstantiated Project costs, etc.</td>
<td>Ensure that future contracts stipulate OPG expectations on robust inventory management to facilitate substantiation of procurement activities and control of OPG-owned project assets.</td>
<td>OPG also needs to have proper project controls infrastructure in-place to support target-price contracts.</td>
</tr>
<tr>
<td>28</td>
<td>Project Controls</td>
<td>Inconsistent use of cost, schedule, and resource tracking tools.</td>
<td>Problem - True schedule position not well understood by all stakeholders. Each stakeholder had difficulty in assessing true cost, schedule, and resource position.</td>
<td>Ineffective resource allocation. Schedule and cost impact.</td>
<td>Decide on standard tools (project-specific) early in the process and allocate resources to ensure consistency and compliance with standards. Utilize simple forms (i.e. inspection, audit, or summary forms) to accurately capture and report on daily progress.</td>
<td>Common scheduling approach required - contractor tracked progress outside of P3 and had to report using P3.</td>
</tr>
<tr>
<td>29</td>
<td>Project Controls</td>
<td>Subcontractor management.</td>
<td>Problem - Subcontract submissions and claims were a straight pass through by the Contractor without any review.</td>
<td>Negotiations more difficult and time consuming. No language in Contract to force the Contractor to review for reasonableness.</td>
<td>More of a relationship issue - Emphasize requirement for a subcontractor management plan and OPG expectations. There are limited opportunities to update our contract T&amp;C’s.</td>
<td>None.</td>
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<td>30</td>
<td>Project Controls</td>
<td>Dispute Resolution processes - OPG's use of a DRB composed of 'professional arbiters'.</td>
<td>Problem - Original DRB process did not result in a streamlined, satisfactory resolution of the major overbreak claim. In particular, usual protections of legal proceedings (like arbitration or litigation) were not available resulting in significant risk to OPG.</td>
<td>A decision that required a &quot;compromise&quot; and ultimately a renegotiation of the DBA. Significant additional legal costs and management time expended in a process with an 'unknown' outcome.</td>
<td>Limit use of DRB's in DB agreements (possibly to technical issues only). Before any 'new' process is used or considered for use as a dispute process, ensure it has been practically evaluated in (a) OPG, or (b) industry. Where speed of resolution outweighs risk of a finding against OPG, consider more informal resolution processes (such as an advisory committee of executives or technical panels of experts) and write the process into the agreement. Arbitration and litigation for significant issues remains the preferred approach.</td>
<td>None.</td>
</tr>
<tr>
<td>31</td>
<td>Health and Safety</td>
<td>Owner-Only execution.</td>
<td>Success - The Owner's Rep. and Plant Group did a very good job separating Strabag's work from the Plant Group's work.</td>
<td>Minimal risk of OPG assuming Constructor role for the entire project.</td>
<td>Requirement to establish clear, consistent boundaries between the contractor and OPG.</td>
<td>None.</td>
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<td>32</td>
<td>Environment</td>
<td>EA commitments (made several years prior) constrained opportunities during detailed design &amp; construction.</td>
<td>Problem - Limited creativity on design and construction that prevents incorporation of Contractor experience and innovations that could reduce Project cost and shorten the duration of the project.</td>
<td>Prevented potential cost &amp; schedule savings such as tunnel alignment through St. Davids Gorge (above problematic Queenston shale), multiple workfaces, excavation methods, construction logistics, etc.</td>
<td>Throughout the EA process on future OPG projects, retain as much flexibility as possible to accommodate subsequent (contractor) experience &amp; innovations during detailed design &amp; construction.</td>
<td>None.</td>
</tr>
<tr>
<td>33</td>
<td>Environment</td>
<td>Environmental Management Plan</td>
<td>Problem - Although this was a comprehensive document and a very good planning tool, it needed updating as the Project proceeded into construction. Tendency was for the document to be more theoretical than practical. Also, the actual Contractor environmental staff numbers were much less than initially defined.</td>
<td>Increased regulatory compliance risks.</td>
<td>Insufficient resources - Probably one manager and 2 assistants would have been the appropriate level of environmental staffing, especially in the initial stages. The use of third party consultants, rather than on site specialists, proved to be the manner of addressing many of the technical issues (e.g. water treatment, storm water management plan).</td>
<td>None.</td>
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<td>34</td>
<td>Environment</td>
<td>Water treatment requirements.</td>
<td>Problem - Plant as initially sized was too small for the amount of water and sediment to be processed. Specifically, the sediment/total solids loading was considerably more than anticipated. The first retention pond was poorly designed/constructed.</td>
<td>Sedimentation plans had to be developed and then amended as the Project proceeded. Also, process water had to be discharged at the Intake, after the FOG, this water should have been treated in the same manner as that being discharged at the Outlet or the piping system within the tunnel should have been restored much more quickly to route the water back to the Outlet.</td>
<td>The addition of the more robust sedimentation pond upstream of the initial pond with the cells operating on a rotating basis greatly alleviated the problem. Use of the sediment, combined with organic matter, proved to be a useful material for site restoration/revegetation.</td>
<td>None.</td>
</tr>
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<td>35</td>
<td>Stakeholder Management</td>
<td>EPSCA Labour Relations</td>
<td>Success - Contractor used a single union (labourers) employed under the EPSCA agreement.</td>
<td>EPSCA prevents major strikes (however does not stop inter-union squabbles over jurisdiction).</td>
<td>Note: This approach required the Contractor to resolve disputes at the labour board and may have prevented expertise from other skilled trades. This is a project-specific LR approach.</td>
<td>None.</td>
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<td>36</td>
<td>Stakeholder Management</td>
<td>Relationship with Regulatory Agencies</td>
<td>Success - Good Relationship with Regulatory Agencies. Upfront consultation and ongoing meetings with key agencies (e.g. MOE, DFO, MNR) and local municipalities – greatly assisted.</td>
<td>Issues could normally be directly addressed.</td>
<td>Upfront consultations and meetings with Regulatory Agencies. Development of working relationships.</td>
<td>None.</td>
</tr>
<tr>
<td>37</td>
<td>Records Management</td>
<td>Project mandated to use OPG's SCI system.</td>
<td>Problem - No explanation/description provided for each SCI number which left room for misinterpretation in numbering/filing of documents, drawings, correspondence, etc.</td>
<td>Many submittals/documents have been given the wrong SCI number; NPG will need to cross-reference to correct the SCI number.</td>
<td>Provide detailed descriptions and examples for each SCI number mandated to be used on a project managed by an outside consultant.</td>
<td>None.</td>
</tr>
<tr>
<td>38</td>
<td>Records Management</td>
<td>Project database.</td>
<td>Problem - Multiple databases were used to track Project information.</td>
<td>Provided ability to locate various information quickly. Using multiple databases required double entry at times. The submittal database was secure which limited the flexibility to make required changes.</td>
<td>An all-inclusive database program to track all project information, which provides program flexibility. Note: These types of programs were not very common at the time this project was initiated.</td>
<td>None.</td>
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</table>
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)

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<td>Finance Controls for Darlington Refurbishment Project</td>
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<td>Darlington Ops Readiness for Refurbishment</td>
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<td>Nuclear Warehousing and Logistics Audit</td>
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<td>AFC 2015 Q3</td>
<td>Real Time Process Controls Systems (&quot;RTPCS&quot;) Security Audit - Nuclear</td>
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<td>Enterprise System Consolidation Project (&quot;ESCP&quot;) - Post Implementation Review</td>
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<td>Finance and Accounting Transactions – Shared Services Audit</td>
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</table>
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


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?

---

**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**

1. **Issue Number: 1.2**
2. **Issue:** Are OPG’s economic and business planning assumptions that impact the nuclear facilities appropriate?

### 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?

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?

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:

<table>
<thead>
<tr>
<th>Typical Bill Impact ($/Month)</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>Average</th>
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<tbody>
<tr>
<td></td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>1.86</td>
<td>1.89</td>
<td>1.05</td>
</tr>
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</table>

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>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>2017 Amount</th>
<th>2016 Amount</th>
<th>2019 Amount</th>
<th>2020 Amount</th>
<th>2021 Amount</th>
<th>Average</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
<td>(f)</td>
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<tr>
<td>1</td>
<td>Typical Consumption (kWh/Month)</td>
<td>789</td>
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<td>789</td>
<td>789</td>
<td>789</td>
<td>789</td>
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<tr>
<td>2</td>
<td>Typical Usage of OPG Generation (kWh/Month) (line 1 x line 11)</td>
<td>392</td>
<td>394</td>
<td>397</td>
<td>388</td>
<td>376</td>
<td>389</td>
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<tr>
<td>3</td>
<td>Typical Bill ($/Month)</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
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<tr>
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<td>Typical Bill Impact ($/Month) (line 2 x line 8 / 1000)</td>
<td>(0.77)</td>
<td>2.39</td>
<td>1.91</td>
<td>2.81</td>
<td>2.97</td>
<td>1.86</td>
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<tr>
<td>5</td>
<td>Typical Bill Impact (%) (line 4 / line 3)</td>
<td>-0.5%</td>
<td>1.6%</td>
<td>1.3%</td>
<td>1.9%</td>
<td>2.0%</td>
<td>1.2%</td>
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<td>6</td>
<td>Prior Year weighted average rate with proposed payment amounts and riders ($/MWh)</td>
<td>60.66</td>
<td>58.70</td>
<td>64.77</td>
<td>69.57</td>
<td>76.82</td>
<td>84.71</td>
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<td>7</td>
<td>Current Year weighted average rate with proposed payment amounts and riders ($/MWh)</td>
<td>58.70</td>
<td>64.77</td>
<td>69.57</td>
<td>76.82</td>
<td>84.71</td>
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<tr>
<td>8</td>
<td>Change in OPG weighted average rate ($/MWh) (line 7 - line 6)</td>
<td>(1.96)</td>
<td>6.07</td>
<td>4.03</td>
<td>7.26</td>
<td>7.80</td>
<td>(84.71)</td>
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<td>9</td>
<td>Total OPG Regulated Production (TWh)</td>
<td>88.3</td>
<td>88.7</td>
<td>89.1</td>
<td>89.6</td>
<td>85.6</td>
<td>87.0</td>
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<tr>
<td>10</td>
<td>Forecast of 2017 Provincial Demand (TWh)</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
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<tr>
<td>11</td>
<td>OPG Proportion of Consumer Usage (line 9 / line 10)</td>
<td>49.7%</td>
<td>49.9%</td>
<td>50.3%</td>
<td>49.1%</td>
<td>47.7%</td>
<td>49.3%</td>
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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.
### Table 2

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Note</th>
<th>2016 per EB-2013-0321 Order plus Rider</th>
<th>2017 per EB-2016-0152 Illustrative Payment Amount plus Rider</th>
<th>2018 per EB-2016-0152 Illustrative Payment Amount plus Rider</th>
<th>2019 per EB-2016-0152 Illustrative Payment Amount</th>
<th>2020 per EB-2016-0152 Illustrative Payment Amount</th>
<th>2021 per EB-2016-0152 Illustrative Payment Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Regulated Hydroelectric Rate Including Rider ($/MWh)</td>
<td>(a)</td>
<td>44.55</td>
<td>43.15</td>
<td>43.77</td>
<td>42.97</td>
<td>43.61</td>
<td>44.27</td>
</tr>
<tr>
<td>2</td>
<td>Nuclear Rate Including Rider ($/MWh)</td>
<td>(b)</td>
<td>72.30</td>
<td>71.03</td>
<td>81.28</td>
<td>80.17</td>
<td>103.70</td>
<td>119.25</td>
</tr>
<tr>
<td>3</td>
<td>Regulated Hydroelectric Production (TWh)</td>
<td>(c)</td>
<td>33.8</td>
<td>39.2</td>
<td>39.2</td>
<td>30.2</td>
<td>30.2</td>
<td>30.2</td>
</tr>
<tr>
<td>4</td>
<td>Forecast Nuclear Production (TWh)</td>
<td>(d)</td>
<td>46.9</td>
<td>38.1</td>
<td>38.5</td>
<td>38.0</td>
<td>37.4</td>
<td>35.4</td>
</tr>
<tr>
<td>5</td>
<td>Total Production (TWh)</td>
<td>(e)</td>
<td>80.6</td>
<td>68.3</td>
<td>68.7</td>
<td>60.3</td>
<td>47.6</td>
<td>65.6</td>
</tr>
<tr>
<td>6</td>
<td>Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)</td>
<td>(f)</td>
<td>18.69</td>
<td>15.09</td>
<td>19.26</td>
<td>18.75</td>
<td>19.51</td>
<td>20.39</td>
</tr>
<tr>
<td>7</td>
<td>Nuclear Portion of Production-Weighted Average Rate ($/MWh)</td>
<td>(g)</td>
<td>41.97</td>
<td>39.61</td>
<td>45.51</td>
<td>50.81</td>
<td>57.32</td>
<td>64.31</td>
</tr>
<tr>
<td>8</td>
<td>Total Production-Weighted Average Rate ($/MWh)</td>
<td>(h)</td>
<td>60.66</td>
<td>58.70</td>
<td>64.77</td>
<td>69.57</td>
<td>76.82</td>
<td>84.71</td>
</tr>
<tr>
<td>9</td>
<td>Percentage Change in Hydroelectric Rate Including Rider</td>
<td>(i)</td>
<td>-3.2%</td>
<td>1.4%</td>
<td>-1.8%</td>
<td>1.5%</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
<tr>
<td>10</td>
<td>Percentage Change in Nuclear Rate Including Rider</td>
<td>(j)</td>
<td>-1.8%</td>
<td>14.4%</td>
<td>11.0%</td>
<td>15.0%</td>
<td>15.0%</td>
<td>15.0%</td>
</tr>
<tr>
<td>11</td>
<td>Percentage Change in Overall Payment Amount</td>
<td>(k)</td>
<td>-3.2%</td>
<td>10.3%</td>
<td>7.4%</td>
<td>10.4%</td>
<td>10.4%</td>
<td>10.4%</td>
</tr>
</tbody>
</table>

**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 (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. Riders included per Ex. H1-3-1 Tables 1 and 2 only - no assumptions made for future riders in the 2019-2021 period
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PAYMENT AMOUNT:</td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
</tr>
<tr>
<td>1</td>
<td>Revenue Requirement Before Stretch Factor $1 ($M)</td>
<td>3,189.9</td>
<td>3,255.0</td>
<td>3,295.1</td>
<td>3,790.0</td>
<td>3,509.8</td>
</tr>
<tr>
<td>2</td>
<td>Nuclear Base OM&amp;A $2</td>
<td>1,210.6</td>
<td>1,226.0</td>
<td>1,248.4</td>
<td>1,264.7</td>
<td>1,276.3</td>
</tr>
<tr>
<td>3</td>
<td>Nuclear Allocated Corporate Costs $3</td>
<td>448.9</td>
<td>437.2</td>
<td>442.7</td>
<td>445.0</td>
<td>454.1</td>
</tr>
<tr>
<td>4</td>
<td>Total OM&amp;A Applicable for Stretch Factor $4</td>
<td>1,659.5</td>
<td>1,663.2</td>
<td>1,691.1</td>
<td>1,709.7</td>
<td>1,730.4</td>
</tr>
<tr>
<td>5</td>
<td>Nuclear Stretch Factor (Ex. A1-3-2, Chart 9)</td>
<td>0.3%</td>
<td>0.3%</td>
<td>0.3%</td>
<td>0.3%</td>
<td>0.3%</td>
</tr>
<tr>
<td>6</td>
<td>Cumulative Nuclear Stretch Dollars ((line 4 x line 5) + Prior Year)</td>
<td>0.0</td>
<td>5.0</td>
<td>10.1</td>
<td>15.2</td>
<td>20.4</td>
</tr>
<tr>
<td>7</td>
<td>Revenue Requirement Net of Stretch Factor ($M) (line 1 - line 6)</td>
<td>3,189.9</td>
<td>3,250.0</td>
<td>3,285.0</td>
<td>3,774.8</td>
<td>3,489.4</td>
</tr>
<tr>
<td>8</td>
<td>Forecast Production $5 (TWh)</td>
<td>38.1</td>
<td>38.5</td>
<td>39.0</td>
<td>37.4</td>
<td>35.4</td>
</tr>
<tr>
<td>9</td>
<td>Illustrative Unsmoothed Payment Amount ($/MWh) (line 7 / line 8)</td>
<td>83.73</td>
<td>84.48</td>
<td>84.17</td>
<td>101.05</td>
<td>98.62</td>
</tr>
<tr>
<td>10</td>
<td>Constant % Increase Without Deferral $6</td>
<td>15.0%</td>
<td>15.0%</td>
<td>15.0%</td>
<td>15.0%</td>
<td>15.0%</td>
</tr>
<tr>
<td>11</td>
<td>Illustrative Constant Rate Incresse Without Deferral ($/MWh)</td>
<td>68.18</td>
<td>78.41</td>
<td>90.17</td>
<td>103.70</td>
<td>119.25</td>
</tr>
<tr>
<td>DEFERRAL AND VARIANCE ACCOUNT PAYMENT RIDER:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Payment Rider $7 ($/MWh)</td>
<td>2.85</td>
<td>2.85</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Total of Nuclear Payment Amount Plus Riders ($/MWh) (line 11 + line 12)</td>
<td>71.03</td>
<td>81.26</td>
<td>90.17</td>
<td>103.70</td>
<td>119.25</td>
</tr>
</tbody>
</table>

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.
Table 1
OPG Nuclear Revenue Requirement

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Requested Revenue Requirement ($M)$^1</td>
<td>N/A</td>
<td>2,671.1</td>
<td>2,788.3</td>
<td>N/A</td>
<td>3,228.5</td>
<td>3,166.9</td>
<td>N/A</td>
</tr>
<tr>
<td>OEB Approved Revenue Requirement ($M)$^1</td>
<td>N/A</td>
<td>2,586.0</td>
<td>2,665.5</td>
<td>N/A</td>
<td>2,790.4</td>
<td>2,877.6</td>
<td>N/A</td>
</tr>
<tr>
<td>OEB &quot;Actual&quot; Revenue Requirement ($M)$^2,3</td>
<td>2,429.8</td>
<td>2,590.0</td>
<td>2,917.1</td>
<td>2,677.5</td>
<td>2,763.1</td>
<td>2,883.7</td>
<td>2,927.5</td>
</tr>
</tbody>
</table>

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.
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 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
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Regulated Hydroelectric</th>
<th>Nuclear</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
</tr>
<tr>
<td>1</td>
<td>Typical Residential Consumer Usage (KWh/Month)&lt;sup&gt;1&lt;/sup&gt;</td>
<td>1,000.0</td>
<td>1,000.0</td>
<td>1,000.0</td>
</tr>
<tr>
<td>2</td>
<td>Gross-up for Line Losses&lt;sup&gt;2&lt;/sup&gt;</td>
<td>1.0522</td>
<td>1.0522</td>
<td>1.0522</td>
</tr>
<tr>
<td>3</td>
<td>OPG Portion&lt;sup&gt;3&lt;/sup&gt;</td>
<td>11.4%</td>
<td>31.9%</td>
<td>43.3%</td>
</tr>
<tr>
<td>4</td>
<td>Residential Consumer Usage of OPG Generation (KWh/Month)</td>
<td>119.8</td>
<td>336.0</td>
<td>455.8</td>
</tr>
<tr>
<td></td>
<td>(line 1 * line 2 * line 3)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Approved Revenue Deficiency After Mitigation&lt;sup&gt;4&lt;/sup&gt;</td>
<td>115.2</td>
<td>483.0</td>
<td>598.3</td>
</tr>
<tr>
<td>6</td>
<td>Approved Production Forecast (TWh)&lt;sup&gt;5&lt;/sup&gt;</td>
<td>31.5</td>
<td>88.2</td>
<td>119.7</td>
</tr>
<tr>
<td>7</td>
<td>Required Recovery ($/MWh)</td>
<td>3.70</td>
<td>5.50</td>
<td>5.00</td>
</tr>
<tr>
<td></td>
<td>(line 5 / line 6)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Typical Monthly Consumer Bill Impact ($)</td>
<td>0.44</td>
<td>1.85</td>
<td>2.28</td>
</tr>
<tr>
<td></td>
<td>(line 4 * line 7)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Typical Monthly Residential Consumer Bill ($)</td>
<td>111.63</td>
<td>111.63</td>
<td>111.63</td>
</tr>
<tr>
<td>10</td>
<td>Percentage Increase in Consumer Bills</td>
<td>0.40%</td>
<td>1.66%</td>
<td>2.05%</td>
</tr>
<tr>
<td></td>
<td>(line 8 / line 9)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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
Table 8
Annualized Residential Consumer Impact Assessment
Board Approved Revenue Requirement
Test Period January 1, 2011 to December 31, 2012

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Notes</th>
<th>Regulated Hydroelectric</th>
<th>Nuclear</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
</tr>
<tr>
<td>1</td>
<td>Typical Residential Consumer Usage (kWh/Month)</td>
<td>1</td>
<td>800.0</td>
<td>800.0</td>
<td>800.0</td>
</tr>
<tr>
<td>2</td>
<td>Gross-up for Line Losses</td>
<td>2</td>
<td>1.0728</td>
<td>1.0728</td>
<td>1.0728</td>
</tr>
<tr>
<td>3</td>
<td>OPG Portion</td>
<td>3</td>
<td>14.0%</td>
<td>35.9%</td>
<td>49.9%</td>
</tr>
<tr>
<td>4</td>
<td>Residential Consumer Usage of OPG Generation (kWh/Month)</td>
<td>(line 1 x line 2 x line 3)</td>
<td>119.9</td>
<td>308.2</td>
<td>428.2</td>
</tr>
</tbody>
</table>

**IMPACT OF RECOVERY OF REVENUE REQUIREMENT DEFICIENCY (SUFFICIENCY):**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Notes</th>
<th>Regulated Hydroelectric</th>
<th>Nuclear</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
</tr>
<tr>
<td>5</td>
<td>Revenue Requirement Deficiency (Sufficiency) Approved for Recovery ($M)</td>
<td>4</td>
<td>(32.5)</td>
<td>(133.5)</td>
<td>(166.0)</td>
</tr>
<tr>
<td>6</td>
<td>Impact of Amortization of Variance and Deferral Account Amounts ($M)</td>
<td>5</td>
<td>(60.2)</td>
<td>216.8</td>
<td>156.7</td>
</tr>
<tr>
<td>7</td>
<td>Amount to be Recovered From Customers ($M) (line 5 + line 6)</td>
<td>(92.6)</td>
<td>83.3</td>
<td>(9.3)</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Forecast Production (TWh)</td>
<td>6</td>
<td>39.7</td>
<td>101.9</td>
<td>141.6</td>
</tr>
<tr>
<td>9</td>
<td>Required Recovery ($/MWh) (line 7 / line 8)</td>
<td></td>
<td>(2.34)</td>
<td>0.82</td>
<td>(0.07)</td>
</tr>
<tr>
<td>10</td>
<td>Typical Monthly Consumer Bill Impact ($) (line 4 x line 9)</td>
<td>(0.28)</td>
<td>0.25</td>
<td>(0.03)</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Typical Monthly Residential Consumer Bill ($)</td>
<td>7</td>
<td>109.40</td>
<td>109.40</td>
<td>109.40</td>
</tr>
<tr>
<td>12</td>
<td>Percentage Change in Consumer Bills</td>
<td></td>
<td>-0.26%</td>
<td>0.23%</td>
<td>-0.03%</td>
</tr>
</tbody>
</table>

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.
Table 6 *

Annualized Residential Consumer Impact Assessment

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Residential</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Typical Consumption(^1) (kWh/Month)</td>
<td>842</td>
</tr>
<tr>
<td>2</td>
<td>Typical Usage of OPG Generation (kWh/Month) (line 1 x line 12)</td>
<td>409</td>
</tr>
<tr>
<td>3</td>
<td>Typical Bill(^1) ($/Month)</td>
<td>116.30</td>
</tr>
<tr>
<td>4</td>
<td>Typical Bill Impact ($/Month) (line 2 x line 8 /1000)</td>
<td>0.74</td>
</tr>
<tr>
<td>5</td>
<td>Typical Bill Impact (%) (line 4 / line 3)</td>
<td>0.6%</td>
</tr>
<tr>
<td>6</td>
<td>Current OPG weighted average Hydro &amp; Nuclear Rate ($/MWh)</td>
<td>49.77</td>
</tr>
<tr>
<td>7</td>
<td>Proposed OPG weighted average Hydro &amp; Nuclear Rate ($/MWh)</td>
<td>51.58</td>
</tr>
<tr>
<td>8</td>
<td>Change in OPG weighted average Hydro &amp; Nuclear Rate ($/MWh) (line 7 - line 6)</td>
<td>1.81</td>
</tr>
<tr>
<td>9</td>
<td>Change in OPG weighted average Hydro &amp; Nuclear Rate (%) (line 8 / line 6)</td>
<td>4%</td>
</tr>
<tr>
<td>10</td>
<td>Total Forecast 2013-14 Regulated Production(^2) (TWh)</td>
<td>138.8</td>
</tr>
<tr>
<td>11</td>
<td>Forecast of Provincial Demand(^3) (TWh)</td>
<td>285.6</td>
</tr>
<tr>
<td>12</td>
<td>OPG Proportion of Consumer Usage (line 10 / line 11)</td>
<td>48.6%</td>
</tr>
</tbody>
</table>

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>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Typical Consumption (kWh/Month)</td>
<td>842</td>
</tr>
<tr>
<td>2</td>
<td>Typical Usage of OPG Generation (kWh/Month)</td>
<td>461</td>
</tr>
<tr>
<td></td>
<td>(line 1 x line 11)</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Typical Bill ($/Month)</td>
<td>118.69</td>
</tr>
<tr>
<td>4</td>
<td>Typical Bill Impact ($/Month)</td>
<td>2.53</td>
</tr>
<tr>
<td></td>
<td>(line 2 x line 8 / 1000)</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Typical Bill Impact (%)</td>
<td>2.1%</td>
</tr>
<tr>
<td></td>
<td>(line 4 / line 3)</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Current OPG weighted average Rate ($/MWh)</td>
<td>49.52</td>
</tr>
<tr>
<td>7</td>
<td>Payment Amounts Order OPG test period weighted average Rate ($/MWh)</td>
<td>55.01</td>
</tr>
<tr>
<td>8</td>
<td>Change in OPG weighted average Rate ($/MWh)</td>
<td>5.49</td>
</tr>
<tr>
<td></td>
<td>(line 7 - line 6)</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Payment Amounts Order Forecast 2014-15 OPG Regulated Production (TWh)</td>
<td>154.6</td>
</tr>
<tr>
<td>10</td>
<td>Forecast of Provincial Demand (TWh)</td>
<td>282.4</td>
</tr>
<tr>
<td>11</td>
<td>OPG Proportion of Consumer Usage (line 9 / line 10)</td>
<td>54.8%</td>
</tr>
</tbody>
</table>

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 Impact¹
January 1, 2015 to December 31, 2016

<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Typical Consumption² (kWh/Month)</td>
<td>842</td>
</tr>
<tr>
<td>2</td>
<td>Typical Usage of OPG Generation (kWh/Month)</td>
<td>489</td>
</tr>
<tr>
<td>3</td>
<td>Typical Bill² ($/Month)</td>
<td>132.57</td>
</tr>
<tr>
<td>4</td>
<td>Typical Bill Impact ($/Month)</td>
<td>1.93</td>
</tr>
<tr>
<td>5</td>
<td>Typical Bill Impact (%)</td>
<td>1.5%</td>
</tr>
<tr>
<td>6</td>
<td>EB-2013-0321 Payment Amounts Order OPG weighted average rate for 2015³ ($/MWh)</td>
<td>54.75</td>
</tr>
<tr>
<td>7</td>
<td>Blended OPG 2015-16 weighted average rate with EB-2014-0370 approved payment riders⁴ ($/MWh)</td>
<td>58.69</td>
</tr>
<tr>
<td>8</td>
<td>Change in OPG weighted average rate ($/MWh)</td>
<td>3.94</td>
</tr>
<tr>
<td>9</td>
<td>EB-2013-0321 Approved 2014-15 OPG Regulated Production⁵ (TWh)</td>
<td>161.6</td>
</tr>
<tr>
<td>10</td>
<td>Forecast of Provincial Demand⁶ (TWh)</td>
<td>278.3</td>
</tr>
<tr>
<td>11</td>
<td>OPG Proportion of Consumer Usage</td>
<td>58.1%</td>
</tr>
</tbody>
</table>

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](http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility) Typical Consumption includes line losses.
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.
<table>
<thead>
<tr>
<th>Line No.</th>
<th>Description</th>
<th>2017 Amount</th>
<th>2018 Amount</th>
<th>2019 Amount</th>
<th>2020 Amount</th>
<th>2021 Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
</tr>
<tr>
<td>1</td>
<td>Typical Consumption (kWh/Month)</td>
<td>789</td>
<td>789</td>
<td>789</td>
<td>789</td>
<td>789</td>
</tr>
<tr>
<td>2</td>
<td>Typical Usage of OPG Generation (kWh/Month)</td>
<td>392</td>
<td>394</td>
<td>397</td>
<td>388</td>
<td>376</td>
</tr>
<tr>
<td>3</td>
<td>Typical Bill ($) (Month)</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
<td>150.58</td>
</tr>
<tr>
<td>4</td>
<td>Typical Bill Impact ($) (Month)</td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>1.86</td>
<td>1.89</td>
</tr>
<tr>
<td>5</td>
<td>Typical Bill Impact (%)</td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.2%</td>
<td>1.3%</td>
</tr>
<tr>
<td>6</td>
<td>Prior Year weighted average rate with proposed payment amounts and riders $\text{^2}$ ($/MWh)</td>
<td>60.86</td>
<td>57.37</td>
<td>61.76</td>
<td>64.45</td>
<td>69.26</td>
</tr>
<tr>
<td>7</td>
<td>Current Year weighted average rate with proposed payment amounts and riders $\text{^2}$ ($/MWh)</td>
<td>57.37</td>
<td>61.76</td>
<td>64.45</td>
<td>69.26</td>
<td>74.27</td>
</tr>
<tr>
<td>8</td>
<td>Change in OPG weighted average rate ($/MWh) (line 7 - line 6)</td>
<td>(3.29)</td>
<td>4.09</td>
<td>2.69</td>
<td>4.81</td>
<td>5.02</td>
</tr>
<tr>
<td>9</td>
<td>Total OPG Regulated Production (TWh)</td>
<td>68.3</td>
<td>68.7</td>
<td>69.3</td>
<td>69.7</td>
<td>65.6</td>
</tr>
<tr>
<td>10</td>
<td>Forecast of 2017 Provincial Demand (TWh)</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
<td>137.6</td>
</tr>
<tr>
<td>11</td>
<td>OPG Proportion of Consumer Usage (line 9 / line 10)</td>
<td>49.7%</td>
<td>49.9%</td>
<td>50.3%</td>
<td>49.1%</td>
<td>47.7%</td>
</tr>
</tbody>
</table>

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/ElectricityYour+ElectricityUtility
2. Typical Consumption includes line losses (Assumed loss factor of 1.0525)
3. Uses Nuclear smoothed rate per Ex. II-3-1 Table 1, RM Hydro rate (illustrative after 2017) per Ex. II-2-1 Table 1
4. From Ex. II-1-2 Table 2, line 8
5. Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of ESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.
**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:**

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.
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.

<table>
<thead>
<tr>
<th>Year</th>
<th>Hours</th>
<th>% of Year</th>
<th>Reg. Rate</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>8519</td>
<td>97</td>
<td>51.52</td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>8425</td>
<td>96</td>
<td>51.52</td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>7462</td>
<td>85</td>
<td>51.52/59.29</td>
<td>Rate change Nov. 1, 2014</td>
</tr>
<tr>
<td>2015</td>
<td>8363</td>
<td>95</td>
<td>59.29</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>6451</td>
<td>98</td>
<td>59.29</td>
<td>YTD Sept. 30, 2016</td>
</tr>
</tbody>
</table>

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital
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?

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

The following response was provided by OPG on October 26, 2016:

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.

In its Decision and Order on GEC’s motion with respect to this interrogatory, the OEB required OPG to respond to the following more defined question: “Assuming that the costs are consistent with the release quality estimate, but work stops at the completion of Unit 2, which is currently planned to be completed in 2020, what would the customer bill impact be both with and without smoothing using the same period for recovery as in the original analysis? For comparison, please provide the customer bill impacts if all four units were to proceed to completion as planned (both smoothed and unsmoothed).”

OPG has not undertaken an assessment of the business strategies it would employ in the scenario posed in the above question. OPG made assumptions necessary to provide a response to the question.

Contextual assumptions made in this analysis include:

- The Pickering units are shut down in 2022/2024, as reflected in OPG’s application
- Bruce refurbishment takes place as scheduled, per the 2015 amended refurbishment agreement between Bruce Power and the IESO
• No changes to CNSC or other regulatory requirements, notwithstanding single-unit station operation at Darlington
• No changes to nuclear decommissioning and waste management costs
• No changes to cost of capital impacts (e.g., financing costs, capital structure resulting from changes in OPG’s risk profile)
• To provide a consistent basis of comparison with the base case, no changes to OPG’s rate smoothing proposal per the pre-filed evidence (i.e. 11%/yr nuclear rate smoothing)

OPG has assumed that work on Darlington refurbishment stops in February 2020, which is the currently planned completion date of Unit 2, and that there is no impact on OPG costs or firm financial commitments prior to that date. The assumed costs resulting from the discontinuation of the refurbishment include expenditures incurred and commitments made to that point with respect to the remaining units, and estimated demobilization costs. The analysis is based on cost flows consistent with the DRP release quality estimate.

The assumed unit shutdown sequence is as follows, with depreciation expense adjusted accordingly: Unit 3 in June 2020, Unit 1 in October 2022, Unit 4 in March 2024 (refer to Ex. L-4.3-8 GEC-009) and Unit 2 in February 2050. OPG has assumed that technical considerations associated with running a four-unit nuclear station with only one operating unit would be overcome without significant operational or cost impacts.

As the non-refurbished units are shut down, OPG has assumed step reductions in Darlington station base and project OM&A expenses, nuclear support and corporate support OM&A expenses, and capital spending. Assumed outage plans have been adjusted to reflect major outage requirements of the non-refurbished units.

Severance and related costs would be incurred in relation to incremental headcount reductions as the non-refurbished units shut down. These have been assumed to be proportional to the Pickering extended operations assumptions. No other changes in labour strategies have been assumed.

OPG’s application provides customer bill impacts on a smoothed basis and unsmoothed basis for the 2017 to 2021 period, and on a smoothed basis for the entire 2017 to 2036 forecast rate smoothing and recovery period. Attachment 1 summarizes the customer bill

---

1 Decommissioning of the three non-refurbished units would be assumed to occur after the Unit 2 safe storage period; therefore, the assumed timing of decommissioning would be similar to the current four-unit refurbishment assumptions. A reduction would occur in assumed lifecycle fuel and other nuclear waste due to earlier shutdown of Units 3, 1, and 4. OPG is unable to provide an impact on the costs given the complex nature of the calculations, underlying information requirements and time available to respond.

2 For purposes of calculating the impact on an unsmoothed basis, nuclear payment amounts are assumed to increase at a uniform annual rate for 2017-2021 such that no revenue requirement amount is deferred for recovery in the Rate Smoothing Deferral Account at end of the five-year period. For 2022-2036, average five-year unsmoothed rates were used (see footnote 5).

3 As explained in OPG’s response to JT3.11, the rate smoothing model underpinning the application is based on the proposed annual revenue requirements for 2017-2021 (Ex. I-1-1-1 Table 1, line 26), and five-year averages of
impacts based on information used to prepare OPG’s May 27, 2016 application and supporting evidence (“DRP as Proposed”). These same impacts, adjusted to reflect the above assumptions with respect to the assumed discontinuation of DRP after completion of Unit 2 in February 2020, are provided in a consistent format in Attachment 1 (“DRP Discontinued”).

Consistent with the approach to calculating customer bill impacts in the pre-filed evidence, changes to non-OPG system costs arising from changes in OPG’s generation are not assumed. Therefore, replacement energy and capacity costs that would be required in the absence of the three Darlington units after their end of their original life are not reflected.

OPG does not believe that the scenario analyzed is a realistic one. Assessment of the business strategies OPG would employ in such a scenario are far more complex than reflected in the indicative assumptions provided above to prepare this response. As OPG noted in its response to Ex. L-4.3-1 Staff-044, “OPG would expect that any decisions regarding the on-going feasibility of the [Darlington Refurbishment Program] schedule or the plan would only be made after a rigorous process of evaluation similar to the one which was undertaken on the decision to proceed with the refurbishment of the Darlington (and the Bruce) units. OPG expects the evaluations and decision-making would involve OPG, the Independent Electricity System Operator, the Ministry of Energy, the Ministry of Finance, other relevant Ministries, and the Cabinet”.

estimated revenue requirements and production forecasts for the 2022-2036 period. These indicative five-year averages were calculated using average rates and production for the 2022-2036 period absent rate smoothing, as provided in Ex. A1-3-3, p. 7, Chart 2.
Customer Bill Impacts: DRP as Proposed vs. DRP Discontinued

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DRP as Proposed:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unsmoothed Bill Impact ($)</td>
<td>1</td>
<td>(0.77)</td>
<td>2.39</td>
<td>1.91</td>
<td>2.81</td>
<td>2.97</td>
<td>1.86</td>
<td>0.51</td>
</tr>
<tr>
<td>Unsmoothed Bill Impact (%)</td>
<td>1</td>
<td>-0.5%</td>
<td>1.6%</td>
<td>1.3%</td>
<td>1.9%</td>
<td>2.0%</td>
<td>1.2%</td>
<td>0.3%</td>
</tr>
<tr>
<td>Smoothed Bill Impact ($)</td>
<td>2</td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>1.86</td>
<td>1.89</td>
<td>1.05</td>
<td>0.42</td>
</tr>
<tr>
<td>Smoothed Bill Impact (%)</td>
<td>2</td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.2%</td>
<td>1.3%</td>
<td>0.7%</td>
<td>0.3%</td>
</tr>
<tr>
<td><strong>DRP Discontinued</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unsmoothed Bill Impact ($)</td>
<td>3</td>
<td>(0.38)</td>
<td>2.92</td>
<td>2.61</td>
<td>4.25</td>
<td>4.78</td>
<td>2.84</td>
<td>0.84</td>
</tr>
<tr>
<td>Unsmoothed Bill Impact (%)</td>
<td>3</td>
<td>-0.3%</td>
<td>1.9%</td>
<td>1.7%</td>
<td>2.8%</td>
<td>3.2%</td>
<td>1.9%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Smoothed Bill Impact ($)</td>
<td></td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>2.24</td>
<td>2.34</td>
<td>1.22</td>
<td>1.58</td>
</tr>
<tr>
<td>Smoothed Bill Impact (%)</td>
<td></td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.5%</td>
<td>1.6%</td>
<td>0.8%</td>
<td>1.1%</td>
</tr>
</tbody>
</table>

Notes

2: Annual smoothed bill impacts supporting the 2017 to 2021 amounts in Ex. I1-2-1 Table 2, lines 4 and 5.
3: Annual unsmoothed bill impacts from annual average nuclear payment amount increases of 18% per year over the 2017 to 2021 period to recover the revised nuclear revenue requirement over the revised production levels for the 2017 to 2021 period. Approach is consistent with approach used in footnote 1 above.
4: Reflects the year-over-year average of the annual customer bill impacts.
**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)

<table>
<thead>
<tr>
<th>Line No</th>
<th>Description</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>Average 2022-2026</th>
<th>Average 2027-2031</th>
<th>Average 2032-2036</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
<td>(f)</td>
<td>(g)</td>
<td>(h)</td>
</tr>
<tr>
<td>1</td>
<td>25% Cost Over Run (Smoothed)</td>
<td>65.81</td>
<td>73.05</td>
<td>81.09</td>
<td>90.01</td>
<td>99.91</td>
<td>138.13</td>
<td>161.60</td>
<td>150.90</td>
</tr>
<tr>
<td>2</td>
<td>100% Cost Over Run (Smoothed)</td>
<td>65.81</td>
<td>73.05</td>
<td>81.09</td>
<td>90.01</td>
<td>99.91</td>
<td>138.13</td>
<td>187.52</td>
<td>223.97</td>
</tr>
<tr>
<td>3</td>
<td>25% Cost Over Run + Delay (Smoothed)(^1)</td>
<td>65.81</td>
<td>73.05</td>
<td>81.09</td>
<td>90.01</td>
<td>99.91</td>
<td>146.25</td>
<td>170.88</td>
<td>146.99</td>
</tr>
<tr>
<td>4</td>
<td>25% Cost Over Run (Unsmoothed)</td>
<td>84.00</td>
<td>84.36</td>
<td>83.68</td>
<td>103.14</td>
<td>100.90</td>
<td>145.92</td>
<td>144.75</td>
<td>130.19</td>
</tr>
<tr>
<td>5</td>
<td>100% Cost Over Run (Unsmoothed)</td>
<td>84.82</td>
<td>83.92</td>
<td>82.16</td>
<td>109.38</td>
<td>107.72</td>
<td>166.47</td>
<td>175.44</td>
<td>156.52</td>
</tr>
<tr>
<td>6</td>
<td>25% Cost Over Run + Delay (Unsmoothed)(^1)</td>
<td>84.00</td>
<td>84.36</td>
<td>82.94</td>
<td>89.51</td>
<td>93.14</td>
<td>164.87</td>
<td>139.88</td>
<td>135.14</td>
</tr>
</tbody>
</table>

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.
<table>
<thead>
<tr>
<th>Line No</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>Average 2017-2021</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
<td>(f)</td>
</tr>
<tr>
<td><strong>SMOOTHED</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25% cost over run</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>1.86</td>
<td>1.89</td>
<td>1.05</td>
</tr>
<tr>
<td>2</td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.2%</td>
<td>1.3%</td>
<td>0.7%</td>
</tr>
<tr>
<td><strong>100% cost over run</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.07</td>
<td>1.86</td>
<td>1.89</td>
<td>1.05</td>
</tr>
<tr>
<td>4</td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.2%</td>
<td>1.3%</td>
<td>0.7%</td>
</tr>
<tr>
<td><strong>25% cost over run + delay</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>(1.29)</td>
<td>1.73</td>
<td>1.11</td>
<td>1.59</td>
<td>2.76</td>
<td>1.18</td>
</tr>
<tr>
<td>6</td>
<td>-0.9%</td>
<td>1.1%</td>
<td>0.7%</td>
<td>1.1%</td>
<td>1.8%</td>
<td>0.8%</td>
</tr>
<tr>
<td><strong>UNSMOOTHED</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25% cost over run</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>2.69</td>
<td>0.23</td>
<td>(0.87)</td>
<td>4.11</td>
<td>(0.64)</td>
<td>1.10</td>
</tr>
<tr>
<td>8</td>
<td>1.8%</td>
<td>0.2%</td>
<td>-0.6%</td>
<td>2.7%</td>
<td>-0.4%</td>
<td>0.7%</td>
</tr>
<tr>
<td><strong>100% cost over run</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>2.87</td>
<td>(0.05)</td>
<td>(1.11)</td>
<td>5.78</td>
<td>(0.56)</td>
<td>1.39</td>
</tr>
<tr>
<td>10</td>
<td>1.9%</td>
<td>0.0%</td>
<td>-0.7%</td>
<td>3.8%</td>
<td>-0.4%</td>
<td>0.9%</td>
</tr>
<tr>
<td><strong>25% cost over run + delay</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>2.69</td>
<td>0.23</td>
<td>(1.00)</td>
<td>1.09</td>
<td>1.35</td>
<td>0.87</td>
</tr>
<tr>
<td>12</td>
<td>1.8%</td>
<td>0.2%</td>
<td>-0.7%</td>
<td>0.7%</td>
<td>0.9%</td>
<td>0.6%</td>
</tr>
</tbody>
</table>

Numbers may not add due to rounding.
<table>
<thead>
<tr>
<th>Line No</th>
<th>2017-2036</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SMOOTHED</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25% cost over run</td>
</tr>
<tr>
<td>1</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>2</td>
<td>Typical Bill Impact (%)</td>
</tr>
<tr>
<td></td>
<td>100% cost over run</td>
</tr>
<tr>
<td>3</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>4</td>
<td>Typical Bill Impact (%)</td>
</tr>
<tr>
<td></td>
<td>25% cost over run + delay¹</td>
</tr>
<tr>
<td>5</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>6</td>
<td>Typical Bill Impact (%)</td>
</tr>
<tr>
<td></td>
<td>UNSMoothED</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25% cost over run</td>
</tr>
<tr>
<td>7</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>8</td>
<td>Typical Bill Impact (%)</td>
</tr>
<tr>
<td></td>
<td>100% cost over run</td>
</tr>
<tr>
<td>9</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>10</td>
<td>Typical Bill Impact (%)</td>
</tr>
<tr>
<td></td>
<td>25% cost over run + delay¹</td>
</tr>
<tr>
<td>11</td>
<td>Typical Bill Impact ($/Month)</td>
</tr>
<tr>
<td>12</td>
<td>Typical Bill Impact (%)</td>
</tr>
</tbody>
</table>
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:

<table>
<thead>
<tr>
<th>Revenue Request</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$1,304</td>
<td>$1,323</td>
<td>$1,299</td>
<td>$1,318</td>
<td>$1,338</td>
</tr>
</tbody>
</table>

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

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital
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 on 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.

<table>
<thead>
<tr>
<th>OPG Rate Impact on OAPPA</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPG’s Annual Rate Impact on OAPPA</td>
<td>$1,715,672</td>
<td>$2,290,028</td>
<td>$1,403,520</td>
<td>$2,507,234</td>
<td>$2,614,467</td>
</tr>
<tr>
<td>Total OAPPA Annual Cost $</td>
<td>$183,885,242</td>
<td>$184,369,626</td>
<td>$183,483,118</td>
<td>$184,586,833</td>
<td>$184,695,065</td>
</tr>
<tr>
<td>Cumulative Increase on OAPPA</td>
<td>$(1,715,672)</td>
<td>$(574,355)</td>
<td>$1,977,875</td>
<td>$4,485,109</td>
<td>$7,101,576</td>
</tr>
<tr>
<td>Cumulative Unit Cost S/MWh Increase on OAPPA</td>
<td>$(1.63)</td>
<td>$0.55</td>
<td>$1.88</td>
<td>$4.27</td>
<td>$6.76</td>
</tr>
</tbody>
</table>

(1) OAPPA Annual Consumption 1,050,388 MWh 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/YourElectricityUtility.

Based on forecast demand for 2017 (137.6 TWh) from Table 3 of IS0 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

Calculated based on OPG_Ex_II-1-1_Att1_OPG_Revenue_Requirement_Work_Form_20160727-OPG_Bill_Imacts_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

Witness Panel: Finance, D&V Accounts, Nuclear Liabilities, Cost of Capital
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, expanding the Industrial Conservation Incentive (and Class A consumer coverage), expected to take effect July 1, 2017.


**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 assess 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.
## OPG Nuclear Payment Amounts

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## Impacts of 2017-2021 Rate Application on Schools

### Annual Consumption Assumptions for Schools (From BPS Energy Reporting 2013 data)

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### Smoothed Rates with no Riders

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## Smoothed Rates with Riders

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## Unsmoothed Rates with Riders

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